November 12, 2002

RE: Tenaska Indiana Generating Station 125-12760-00039 125-13571-00039

TO: Interested Parties / Applicant

FROM: Paul Dubenetzky
Chief, Permits Branch
Office of Air Quality

Notice of Decision - PSD Permit Approval

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision on the enclosed Prevention of Significant Deterioration (PSD) Permit. Pursuant to IC 13-15-5-3 and the federal requirements codified at 40 CFR Part 124.15 (b), this permit is effective thirty (30) days after the service of this notice. This permit may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3-7 and IC 13-15-6-1 require that you file a petition for administrative review. This petition describing your intent must be submitted to the Office of Environmental Adjudication, ISTA Building, 150 W. Market Street, Suite 618, Indianapolis, IN 46204, **within eighteen (18) days of service of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) the date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location and date of this notice. Additionally, IC 13-15-6-2 requires that a petition include:

(1) the name and address of the person making the request; and
(2) the interest of the person making the request; and
(3) identification of any persons represented by the person making the request; and
(4) the reasons, with particularity, for the request; and
(5) the issues, with particularity, proposed for consideration at the hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

(over)

If you wish to challenge this decision under federal law, 40 CFR 124.19 requires that you petition the Environmental Appeals Board **within thirty (30) days of the service of this notice**, at the following address:

U.S. Environmental Protection Agency
Environmental Appeals Board (MC-1103B)
Ariel Rios Building
1200 North Pennsylvania Ave., N.W.
Washington, D.C. 20406

Pursuant to 40 CFR Part 124.19, the petition must include a statement of the reasons supporting review, including a demonstration that any issues being raised were raised during the public comment period or public hearing. When appropriate, the petition must also include a showing that the permit condition in question is based on:

(1) a finding of fact or conclusion of law which is clearly erroneous; or,
(2) an exercise of discretion or an important policy consideration which the Environmental Appeals Board should, in its discretion, review.

Pursuant to 40 CFR Part 124.19, the Environmental Appeals Board shall provide public notice of any grant or review. Notice of denial or review shall be sent only to the person(s) requesting review.

If you technical questions regarding the enclosed document, please call the Office of Air Quality, Permits Branch at 317-233-0178. Callers from within Indiana may call toll-free at 1-800-451-6027, ext. 3-0178

Enclosures

FNPSD30.WPD 8/21/02

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We make Indiana a cleaner, healthier place to live.

Frank O'Bannon
Governor

Lori F. Kaplan
Commissioner

100 North Senate Avenue
P.O. Box 6015
Indianapolis, Indiana 46206-6015
(317) 232-8603
(800) 451-6027
www.in.gov/idem

NEW SOURCE CONSTRUCTION PERMIT
Prevention of Significant Deterioration (PSD) Permit
Office of Air Quality

Tenaska Indiana Partners, L.P.
Tenaska Indiana Generating Station
County Road 625 East
Otwell, IN 47564

(herein known as the Permittee) is hereby authorized to construct and operate subject to the conditions contained herein, the emission units described in Section A (Source Summary) of this permit.

This permit is issued to the above mentioned company under the provisions of 326 IAC 2-1.1, 326 IAC 2-5.1, 326 IAC 2-6.1 and 40 CFR 52.780, with conditions listed on the attached pages.

This permit is issued under the provisions of 326 IAC 2 and 40 CFR Part 52.21 (Prevention of Significant Deterioration) and 40 CFR 124 (Procedure for Decision Making), with conditions listed on the attached pages.

Permit No.: CP 125-12760-00039	
Original signed by Paul Dubenetzky Issued by: Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date: November 12, 2002

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-5.1-3(c)] [326 IAC 2-6.1-4(a)]

The Permittee has proposed to construct and operate a 1750 megawatt electric generating station.

Authorized Individual:	Michael C. Lebens, Vice President
Source Address:	County Road 625 East, Otwell, IN 47564
Mailing Address:	1044 N.115 Street, Suite 400, Omaha NE 68154
Phone Number:	(402) 691-9500
SIC Code:	4911
County Location:	Pike
County Status:	Attainment for all criteria pollutants
Source Status:	Major (Utility Steam Electric Generating Unit), under PSD 1 of the 28 listed sources Major Source under Part 70 Operating Permit

A.2 Emissions units and Pollution Control Equipment Summary

This stationary source is approved to construct and operate the following emissions units and pollution control devices:

(a) Six (6) natural gas-fired combustion turbines designated as units GT-1 through GT-6 with a maximum heat input capacity of 2,112 MMBtu/hr per unit higher heating value (HHV). Six (6) heat recovery steam generators, designated as units HRSG-1 through HRSG-6 with six (6) associated duct burners. The duct burners associated with each HRSG are rated at a maximum heat input of 550 MMBtu/hr HHV and exhaust to stacks designated ST-1 through ST-6. The emissions from the gas-fired combustion turbines and duct burners are controlled using Selective Catalytic Reduction Systems, low-NOx combustors and burners, combustion controls, and use of clean burning natural gas as a fuel.

(b) Two (2) reheat condensing steam turbines.

(c) One (1) auxiliary boiler, designated as Boil, with a maximum heat input rating of 40 MMBtu/hr that exhausts to a stack designated as BOIL 100.

(d) Two (2) cooling towers, designated as Cool-1 and Cool-2, that exhaust to stacks designated as Cool - 1 and Cool - 2.

(e) Six (6) black-start diesel generators, designated as BSG1 through BSG6, each with a maximum heat input of 19.1 MMBtu/hr utilizing low sulfur diesel fuel and exhausting to stacks designated BSG-1 through BSG-6

(f) One (1) emergency diesel generator, designated as AUG-1, with a maximum heat input capacity of 10.1 MMBtu/hr HHV utilizing low sulfur diesel fuel and exhausting to a stack designated as Emergency.

(g) One (1) diesel fire pump, designated as DFP-1, with a maximum rated heat input capacity of 0.95 MMBtu/hr HHV utilizing low sulfur diesel fuel and exhausting to a stack designated as Fire Pump.

A.3 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3);

(c) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

A.4 Acid Rain Permit Applicability [326 IAC 2-7-2]

This stationary source shall be required to submit a Phase II, Acid Rain permit application in accordance with 40 CFR 72.30 (Applicability) because:

(a) The combustion turbines are new units under 40 CFR 72.6.

SECTION B GENERAL CONSTRUCTION CONDITIONS

THIS SECTION OF THE PERMIT IS BEING ISSUED UNDER THE PROVISIONS OF 326 IAC 2-1.1 AND 40 CFR 52.780, WITH CONDITIONS LISTED BELOW.

B.1 Permit No Defense [IC 13]

This permit to construct does not relieve the Permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13-17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements.

B.2 Definitions

Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, any applicable definitions found in IC 13-11, 326 IAC 1-2, and 326 IAC 2-1.1-1 shall prevail.

B.3 Effective Date of the Permit [IC13-15-5-3]

Pursuant to 40 CFR 124.15, 40 CFR 124.19, and 40 CFR 124.20, the effective date of this permit will be thirty (30) days after the service of notice of the decision, since comments are received during the public comment period for this permit. Three (3) days shall be added to the thirty (30) day period if service of notice is by mail.

B.4 Permit Expiration Date [326 IAC 2-2-8(a)(1)] [40 CFR 52.21(r)(2)]

Pursuant to 40 CFR 52.21(r)(2) and 326 IAC 2-2-8(a)(1) (PSD Requirements: Source Obligation) this permit to construct shall expire if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is discontinued for a continuous period of eighteen (18) months or more, or if construction is not completed within reasonable time.

B.5 First Time Operation Permit [326 IAC 2-6.1]

This document shall also become a first time operating permit pursuant to 326 IAC 2-5.1-3 when, prior to start of operation, the following requirements are met:

(a) Any modifications required by 326 IAC 2-1.1 and 326 IAC 2-7-10.5 as a result of a change in the design or operation of emissions units described by this permit must be obtained prior to obtaining an Operation Permit Validation Letter.

(b) The attached Affidavit of Construction shall be submitted to the Office of Air Quality (OAQ), Permit Administration & Development Section.

(1) If the Affidavit of Construction verifies that the facilities covered in this Construction Permit were constructed as proposed in the application, then the facilities may begin operating on the date the Affidavit of Construction is postmarked or hand delivered to IDEM.

(2) If actual construction of the emissions units differs from the construction proposed in the application or the permit in a manner that is regulated under the provisions of 326 IAC 2-2, the source may not begin operation until the source modification has been revised pursuant to the provisions of that rule and the provisions of 326 IAC 2-1.1-6 and an Operation Permit Validation Letter is issued.

(3) If actual construction of the emissions units differs from the construction proposed in the application or the permit in a manner that is not regulated under the provisions of 326 IAC 2-2, the source may not begin operation until the source modification has been revised pursuant to the provisions of that rule and the provisions of 326 IAC 2-6.1-6 and an Operation Permit Validation Letter is issued.

(c) If construction is completed in phases; i.e., the entire construction is not done continuously, a separate affidavit must be submitted for each phase of construction. Any permit conditions associated with operation start up dates such as stack testing for New Source Performance Standards (NSPS) shall be applicable to each individual phase.

(d) Upon receipt of the Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section, the Permittee shall attach it to this document.

(e) The Operation Permit will be subject to annual operating permit fees pursuant to 326 IAC 2-7-19 (Fees).

(f) Pursuant to 326 IAC 2-7-4(a)(1)(A)(ii) and 326 IAC 2-5.1-4, the Permittee shall apply for a Title V operating permit within twelve (12) months of the date on which the source first meets an applicability criterion of 326 IAC 2-7-2.

B.6 NSPS Reporting Requirement

Pursuant to the New Source Performance Standards (NSPS), Part 60.7, Part 60.8, the source owner/operator is hereby advised of the requirement to report the following at the appropriate times:

(a) Commencement of construction date (no later than 30 days after such date);

(b) Anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

(c) Actual start-up date (within 15 days after such date); and

(d) Date of performance testing (at least 30 days prior to such date), when required by a condition elsewhere in this permit.

Reports are to be sent to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue P.O. Box 6015
Indianapolis, IN 46206-6015

The application and enforcement of these standards have been delegated to the IDEM, OAQ. The requirements of 40 CFR Part 60 are also federally enforceable.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

C.1 Major Source

Pursuant to 326 IAC 2-2 (Prevention of Significant Deterioration) and 40 CFR 52.21, and 326 IAC 2-7 (Part 70 Permit Program) this source is a major source.

C.2 Preventive Maintenance Plan [326 IAC 1-6-3]

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plan (PMP) ninety (90) days after the commencement of normal operations after the first construction phase, including the following information on each emissions unit:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions;

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

(b) The Permittee shall implement the Preventive Maintenance Plans as necessary to ensure that failure to implement the Preventive Maintenance Plans does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) The PMP shall be submitted to IDEM, OAQ upon request and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its Preventive Maintenance Plans whenever lack of proper maintenance causes or contributes to any violation.

C.3 Source Modification [326 IAC 2-7-10.5]

(a) The Permittee must comply with the requirements of 326 IAC 2-7-10.5 whenever the Permittee seeks to construct new emissions units, modify existing emissions units, or otherwise modify the source.

(b) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

Any such application should be certified by the “responsible official” as defined by 326 IAC 2-7-1(34) only if a certification is required by the terms of the applicable rule.

C.4 Inspection and Entry [326 IAC 2-5.1-3(e)(4)(B)] [326 IAC 2-6.1-5(a)(4)]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee’s right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a permitted source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

(b) Have access to and copy any records that must be kept under this title or the conditions of this permit or any operating permit revisions;

(c) Inspect any processes, emissions units (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit or any operating permit revisions;

(d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) Utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

C.5 Transfer of Ownership or Operation [326 IAC 2-6.1-6(d)(3)]

Pursuant to [326 IAC 2-6.1-6(d)(3)]

(a) In the event that ownership of this source is changed, the Permittee shall notify IDEM, OAQ, Permits Branch within thirty (30) days of the change.

(b) The written notification shall be sufficient to transfer the permit to the new owner by a notice-only change pursuant to 326 IAC 2-6.1-6(d)(3).

(c) IDEM, OAQ shall issue a revised permit.

The notification, which shall be submitted by the Permittee, does require the certification by the “authorized individual” as defined by 326 IAC 2-1.1-1.

C.6 Permit Revocation [326 IAC 2-1.1-9]

Pursuant to 326 IAC 2-1.1-9(a)(Revocation of Permits), this permit to construct and operate may be revoked for any of the following causes:

(a) Violation of any conditions of this permit.

(b) Failure to disclose all the relevant facts or misrepresentation in obtaining this permit.

(c) Changes in regulatory requirements that mandate either a temporary or permanent reduction of discharge of contaminants. However, the amendment of appropriate sections of this permit shall not require revocation of this permit.

(d) Noncompliance with orders issued pursuant to 326 IAC 1-5 (Episode Alert Levels) to reduce emissions during an air pollution episode.

(e) For any other cause that establishes in the judgment of the commissioner the fact that continuance of this permit is not consistent with the purposes of this article.

C.7 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes, sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute non-overlapping integrated averages for a continuous opacity) monitor in a six (6) hour period.

C.8 Fugitive Dust Emissions [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

C.9 Stack Height [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions) for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted by using good engineering practices (GEP) pursuant to 326 IAC 1-7-3.

Testing Requirements

C.10 Performance Testing [326 IAC 3-6]

(a) Compliance testing on new emissions units shall be conducted within 60 days after achieving maximum production rate, but no later than180 days after initial start-up, if specified in Section D of this approval. All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

A test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

no later than thirty-five (35) days prior to the intended test date. The Permittee shall submit a notice of the actual test date to the above address so that it is received at least two weeks prior to the test date.

(b) IDEM, OAQ must receive all test reports within forty-five (45) days after the completion of the testing. IDEM, OAQ may grant an extension, if the source submits to IDEM, OAQ, a reasonable written explanation within five (5) days prior to the end of the initial forty-five (45) day period.

The documentation submitted by the Permittee does not require certification by the “authorized individual” as defined by 326 IAC 2-1.1-1(1).

Compliance Monitoring Requirements

C.11 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall prepare written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) These ERPs shall be submitted for approval to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

within 180 days from the date on which this source commences operation.

(c) If the ERP is disapproved by IDEM, OAQ, the Permittee shall have an additional thirty (30) days to resolve the differences and submit an approvable ERP. If after this time, the Permittee does not submit an approvable ERP, then IDEM, OAQ shall supply such a plan.

(d) These ERPs shall state those actions that will be taken, when each episode level is declared, to reduce or eliminate emissions of the appropriate air pollutants.

(e) Said ERPs shall also identify the sources of air pollutants, the approximate amount of reduction of the pollutants, and a brief description of the manner in which the reduction will be achieved.

(f) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-3 (Implementation of ERP), the Permittee shall put into effect the actions stipulated in the approved ERP upon direct notification by OAQ that a specific air pollution episode is in effect.

C.12 Compliance Monitoring [326 IAC 2-1.1-11]

Compliance with applicable requirements shall be documented as required by this permit. The Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. All monitoring and record keeping requirements not already legally required shall be implemented when operation begins.

C.13 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-6-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment. In addition, prompt corrective action shall be initiated whenever indicated.

(b) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(c) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or will be down for calibration, maintenance, or repairs for a period of four (4) hours or more, supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.

(d) Nothing in this condition, or in Section D of this permit, shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5-1 (d)(1), 40 CFR 72 (Acid Rain Permit) and 40 CFR 60, Subpart GG (Stationary Gas Turbines).

C.14 Monitoring Methods [326 IAC 3]

Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, or other approved methods as specified in this permit.

C.15 Actions Related to Noncompliance Demonstrated by a Stack Test

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate corrective actions. The Permittee shall submit a description of these corrective actions to IDEM, OAQ within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize emissions from the affected emissions unit while the corrective actions are being implemented. IDEM, OAQ shall notify the Permittee within thirty (30) days if the corrective actions taken are deficient. The Permittee shall submit a description of additional corrective actions taken to IDEM, OAQ within thirty (30) days of receipt of the notice of deficiency. IDEM, OAQ reserve the authority to use enforcement activities to resolve noncompliant stack tests.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (180) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred and eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline. Failure of the second test to demonstrate compliance with the appropriate permit conditions may be grounds for immediate revocation of the permit to operate the affected emissions unit.

The documents submitted pursuant to this condition do require the certification by the “authorized

Record Keeping and Reporting Requirements

C.16 Emission Reporting [326 IAC 2-6]

Pursuant to 326 IAC 2-6, the owner/operator of this Source must annually submit an emission statement of the Source. The annual statement must be received by July 1 of each year and must contain the minimum requirements as specified in 326 IAC 2-6-4.

C.17 Malfunctions Report [326 IAC 1-6-2]

Pursuant to 326 IAC 1-6-2 (Records; Notice of Malfunction):

(a) A record of all malfunctions, including startups or shutdowns of any facility or emission control equipment, which result in violations of applicable air pollution control regulations or applicable emission limitations shall be kept and retained for a period of three (3) years and shall be made available to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) or appointed representative upon request.

(b) When a malfunction of any facility or emission control equipment occurs which lasts more than one (1) hour, said condition shall be reported to OAQ using the Malfunction Report Forms (2 pages). Notification shall be made by telephone or facsimile as soon as practicable, but in no event later than four (4) daytime business hours after the beginning of said occurrence.

(c) Failure to report a malfunction of any emission control equipment shall constitute a violation of 326 IAC 1-6 and any other applicable rules. Information of the scope and expected duration of the malfunction shall be provided, including the items specified in 326 IAC 1-6-2(a)(1) through (6).

(d) Malfunction is defined as any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner. [326 IAC 1-2-39]

C.18 Monitoring Data Availability [326 IAC 2-6.1-2] [IC 13-14-1-13]

(a) With the exception of performance tests conducted in accordance with Section C-Performance Testing, all observations, sampling, maintenance procedures, and record keeping, required as a condition of this permit shall be performed at all times the equipment is operating at normal representative conditions.

(b) As an alternative to the observations, sampling, maintenance procedures, and record keeping of subsection (a) above, when the equipment listed in Section D of this permit is not operating, the Permittee shall either record the fact that the equipment is shut down or perform the observations, sampling, maintenance procedures, and record keeping that would otherwise be required by this permit.

(c) If the equipment is operating but abnormal conditions prevail, additional observations and sampling should be taken with a record made of the nature of the abnormality.

(d) If for reasons beyond its control, the operator fails to make required observations, sampling, maintenance procedures, or record keeping, reasons for this must be recorded.

(e) At its discretion, IDEM may excuse such failure providing adequate justification is documented and such failures do not exceed five percent (5%) of the operating time in any quarter.

(f) Temporary, unscheduled unavailability of staff qualified to perform the required observations, sampling, maintenance procedures, or record keeping shall be considered a valid reason for failure to perform the requirements stated in (a) above.

C.19 General Record Keeping Requirements [326 IAC 2-6.1-2]

(a) Records of all required monitoring data and support information shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be kept at the source location for a minimum of three (3) years and available upon the request of an IDEM, OAQ representative. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a written request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Records of required monitoring information shall include, where applicable:

(1) The date, place, and time of sampling or measurements;

(2) The dates analyses were performed;

(3) The company or entity performing the analyses;

(4) The analytic techniques or methods used;

(5) The results of such analyses; and

(6) The operating conditions existing at the time of sampling or measurement.

(c) Support information shall include, where applicable:

(1) Copies of all reports required by this permit;

(2) All original strip chart recordings for continuous monitoring instrumentation;

(3) All calibration and maintenance records;

(4) Records of preventive maintenance shall be sufficient to demonstrate that failure to implement the Preventive Maintenance Plan did not cause or contribute to a violation of any limitation on emissions or potential to emit. To be relied upon subsequent to any such violation, these records may include, but are not limited to: work orders, parts inventories, and operator's standard operating procedures. Records of response steps taken shall indicate whether the response steps were performed in accordance with the Compliance Response Plan required by Section C - Compliance Monitoring Plan - Failure to take Response Steps, of this permit, and whether a deviation from a permit condition was reported. All records shall briefly describe what maintenance and response steps were taken and indicate who performed the tasks.

(d) All record keeping requirements not already legally required shall be implemented when operation begins.

C.20 General Reporting Requirements [326 IAC 2-1.1-11] [326 IAC 2-6.1-2] [IC 13-14-1-13]

(a) To affirm that the source has met all the compliance monitoring requirements stated in this permit the source shall submit a Semi-annual Compliance Monitoring Report. Any deviation from the requirements and the date(s) of each deviation must be reported. The Compliance Monitoring Report shall include the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(b) The report required in (a) of this condition and reports required by conditions in Section D of this permit shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(d) Unless otherwise specified in this permit, any semi-annual report shall be submitted within thirty (30) days of the end of the reporting period. The reports require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(e) All instances of deviations must be clearly identified in such reports. A reportable deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit or a rule. It does not include:

(1) An excursion from compliance monitoring parameters as identified in Section D of this permit unless tied to an applicable rule or limit; or

(2) A malfunction as described in 326 IAC 1-6-2; or

(3) Failure to implement elements of the Preventive Maintenance Plan unless lack of maintenance has caused or contributed to a deviation; or

(4) Failure to make or record information required by the compliance monitoring provisions of Section D unless such failure exceeds 5% of the required data in any calendar quarter.

A Permittee's failure to take the appropriate response step when an excursion of a compliance monitoring parameter has occurred or failure to monitor or record the required compliance monitoring is a deviation.

(f) Any corrective actions or response steps taken as a result of each deviation must be clearly identified in such reports.

(g) The first report shall cover the period commencing on the date start of normal operation after the first phase of construction and ending on the last day of the reporting period.

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Facility Description [326 IAC 2-5.1-3]:

(a) Six (6) natural gas-fired combustion turbines designated as units GT-1 through GT-6 with a maximum heat input capacity of 2,112 MMBtu/hr higher heating value (HHV) per unit. Six (6) heat recovery steam generators, designated as units HRSG-1 through HRSG-6 with six (6) associated duct burners. Each duct burner is rated at a maximum heat input of 550 MMBtu/hr HHV. The combustion turbines and HRSG duct burners exhaust to stacks designated ST-1 through ST-6. The emissions from the gas-fired combustion turbines and duct burners are controlled using Selective Catalytic Reduction Systems, low-NOx combustors and burners, combustion controls, and use of clean burning natural gas as a fuel.

(b) Two (2) reheat condensing steam turbines.

(c) Two (2) cooling towers, designated as Cool-1 and Cool-2 exhausting to stack groups designated as Cool - 1 and Cool - 2.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.1.1 Particulate Matter (PM/PM_{10}) Emission Limitations for Combustion Turbines/Duct Burners [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), the PM (filterable) emissions from each combustion turbine shall not exceed 0.005 pounds per MMBtu (higher heating value basis) and shall not exceed 9.0 pounds per hour.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the PM_{10} (filterable and condensible) emissions from each combustion turbine shall not exceed 0.005 pounds per MMBtu (higher heating value basis) and shall not exceed 9.0 pounds per hour.

(c) Pursuant to 326 IAC 2-2 (PSD Requirements), the PM (filterable) emissions from each combustion turbine when its associated duct burner is operating, shall not exceed 0.0075 lb/MMBtu (higher heating value basis) and shall not exceed 19.4 pounds per hour.

(d) Pursuant to 326 IAC 2-2 (PSD Requirements), the PM_{10} (filterable and condensible) emissions from each combustion turbine when its associated duct burner is operating, shall not exceed 0.0075 lb/MMBtu (higher heating value basis) and shall not exceed 19.4 pounds per hour.

D.1.2 Opacity Limitations [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the opacity from each combustion turbine stack shall not exceed twenty (20) percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent.

D.1.3 Limitation for Power Augmentation for Combustion Turbines [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD requirements) operation of each combustion turbine with power augmentation shall not exceed 1500 hours per 12 consecutive month period rolled on monthly basis.

D.1.4 Nitrogen Oxides (NO_X) Emission Limitations for Combustion Turbines/Duct Burners [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD Requirements) each combustion turbine/steam generating unit shall comply with the following, excluding startup and shutdown periods:

(1) During normal combined-cycle operation (fifty (50) percent load or more), the NO_X emissions from each combustion turbine stack shall not exceed 2.5 ppmvd corrected to fifteen (15) percent oxygen, average on a three (3) operating hour period and shall not exceed 19.1 pounds per hour.

(2) During normal combined cycle operation (fifty (50) percent load or more), the NO_X emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 2.5 ppmvd corrected to fifteen (15) percent oxygen, averaged on a three (3) operating hour period, and shall not exceed 24.1 pounds per hour.

(b) The duct burners shall not be operated until normal combined cycle operation begins.

(c) Each combustion turbine shall be equipped with dry low-NO_X combustors and operated using good combustion practices to control NO_X emissions.

(d) A selective catalytic reduction (SCR) system shall be installed and operated at all times to control NOx emissions when the combustion turbines are operating, except during periods of startup and shutdown.

(e) Use natural gas as the only fuel.

(f) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual NO_X emission from each combustion turbine and associated duct burner, excluding startup and shutdown emissions, shall not exceed 87 tons per year.

D.1.5 Carbon Monoxide (CO) Emission Limitations for Combustion Turbines/Duct Burners[326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), each combustion turbine/steam generating unit shall comply with the following, excluding startup and shutdown periods:

(1) During combined-cycle operation at loads greater than 65 %, the CO emissions from each combustion turbine shall not exceed 3.6 ppmvd corrected to fifteen (15) percent oxygen, averaged on a 24-operating hour period and shall not exceed 16.7 pounds per hour.

(2) During combined-cycle operation at loads greater than 50 % and less than or equal to 65%, the CO emissions from each combustion turbine shall not exceed 6 ppmvd corrected to fifteen (15) percent oxygen, averaged on a 24-operating hour period and shall not exceed 27.8 pounds per hour.

(3) During normal operation (fifty (50) percent load or more), the CO emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 5.4 ppmvd corrected to fifteen (15) percent oxygen, based on a 24-operating hour period and shall not exceed 31.7 pounds per hour.

(4) During power augmentation mode, the CO emissions from each combustion turbine stack shall not exceed 11 ppm corrected to fifteen (15) percent oxygen, averaged on a 24-operating hour basis and shall not exceed 60.3 pounds per hour for each combustion turbine and duct burner.

(b) The duct burners shall not be operated until normal combined cycle operation begins.

(c) Good combustion practices shall be applied to minimize CO emissions.

(d) Use natural gas as the only fuel.

(e) An oxidation catalyst system shall be installed and operated at all times to control CO emissions when the combustion turbines are operating.

(f) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual CO emission from each combustion turbine and associated duct burner, excluding startup and shutdown emissions, shall not exceed 74.2 tons per year.

D.1.6 Sulfur Dioxide (SO_2) and H_2SO_4 mist Emission Limitations for Combustion Turbines/Duct Burners [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements), each combustion turbine and duct burner shall comply with the following:

(1) During normal combined-cycle operation (fifty (50) percent load or more), the SO_2 emissions from each combustion turbine and duct burner shall not exceed 0.0055 pounds per MMBtu (higher heating value basis) and shall not exceed 14.7 pounds per hour.

(2) During normal combined-cycle operation (fifty (50) percent load or more), the H_2SO_4 mist emissions from each combustion turbine and duct burner shall not exceed 0.0034 lb/MMBtu (higher heating value basis) and shall not exceed 8.1 pounds per hour.

(3) The use of pipeline natural gas as the only fuel for the combustion turbines and duct burners. The sulfur content of the natural gas shall not exceed 0.6 grains per 100 scf as defined in 40 CFR 72.

(4) Perform good combustion practice.

D.1.7 Volatile Organic Compound (VOC) Emission Limitations for Combustion Turbines/Duct Burners [326 IAC 2-2] [326 IAC 8-1-6]

Pursuant to 326 IAC 8-1-6 (VOC Requirements) and 326 IAC 2-2 (PSD Requirements), the following requirements must be met:

(1) The VOC emissions from each combustion turbine shall not exceed 0.0015 pounds per MMBtu (higher heating value basis) and shall not exceed 1.6 pounds per hour.

(2) The VOC emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 0.0051 pounds per MMBtu (higher heating value basis) and shall not exceed 12.1 pounds per hour.

(3) During the power augmentation mode, the VOC emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 0.01 pounds per MMBtu (higher heating value basis) and shall not exceed 15.3 pounds per hour.

(4) The use of natural gas as the only fuel.

(5) Good combustion practice shall be implemented and oxidation catalyst be installed and operated to minimize VOC emissions.

D.1.8 40 CFR 60, Subpart GG (Stationary Gas Turbines)

The six (6) natural gas combustion turbines identified as GT-1 through GT-6 are subject to 40 CFR Part 60 Subpart GG (Stationary Gas Turbines) because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour (10 MMBtu per hour), based on the lower heating value of the fuel fired.

Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) Limit nitrogen oxides emissions from the combustion turbines to 0.0113% by volume at 15% oxygen on a dry basis, as required by 40 CFR 60.332, to:

$$STD = 0.0075 \frac{(14.4)}{Y} + F,$$

where STD = allowable NO_x emissions (percent by volume at 15 percent oxygen on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) Limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight.

D.1.9 40 CFR Part 60, Subpart Da (Electric Utility Steam Generating Units)

The heat recovery steam generator (HRSG) duct burners (DB) are subject to 40 CFR Part 60, Subpart Da because the heat input capacity is greater than 250 MMBtu/hr on a higher heating value basis. Pursuant to 40 CFR Part 60, Subpart Da,

(a) The opacity from each combustion turbine stack, when its associated duct burner is operating, shall not exceed twenty (20) percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction. This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

(b) The PM emissions from each duct burner shall not exceed 0.03 pounds per MMBtu heat input on a higher heating value basis.

(c) Each duct burner shall not exceed 1.6 lb/MW-hr NO_X on a thirty (30) day rolling average basis.

(d) Each duct burner shall not exceed 0.20 pounds SO_2 per MMBtu heat input, determined on a 30-day rolling average basis.

D.1.10 Formaldehyde Limitations [326 IAC 2-4.1-1]

The formaldehyde emission from the combined cycle combustion turbines shall not exceed 0.00016 lb/MMBtu. This shall limit the formaldehyde emissions from the entire source to less than ten (10) tons per year and make requirements of 326 IAC 2-4.1 not applicable. Any increase in single Hazardous Air Pollutant (HAP) emissions greater than the threshold specified above and combined HAPs greater than twenty five (25) tons per year, from the entire Source must be approved by the Office of Air Quality (OAQ) before such change may occur.

D.1.11 Ammonia Limitations [326 IAC 2-1.1-5] [326 IAC 2-2]

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements) and 326 IAC 2-2, to maintain the optimum performance of the SCR, the ammonia emissions from each combined cycle combustion turbine stack:

(a) shall not exceed ten (10) ppmvd corrected to 15% O_2 on 3 hour block average basis, and

(b) shall not exceed 140 tons per calendar year.

D.1.12 Startup and Shutdown Limitations for Combustion Turbines [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements),

(a) For any combustion turbine unit, a startup is defined as the period of time from initiation of combustion firing until the unit reaches a minimum load of fifty (50) percent.

(b) Shutdown is defined as operation at less than fifty (50) percent load descending to no load.

(c) An event is defined as one startup and one shutdown and shall not exceed 5.6 hours (Startup is 4.95 hours + Shutdown is 0.67 hours).

(d) Each turbine unit shall comply with the following:

i. The total number of hours under startup/shutdown mode shall not exceed 650 hours on a 12 consecutive month period rolled on monthly basis.

ii. The NO_X emissions from each combustion turbine shall be less than 827 pounds per event.

iii. The CO emissions from each combustion turbine shall be less than 13,558 pounds per event.

D.1.13 Cooling Tower Particulate Matter Emissions (PM/PM_{10}) [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) each cooling tower shall comply with the following:

(a) The drift losses from the cooling tower shall not exceed 0.0005% of cooling water,

(b) PM emissions shall be less than 1.1 pounds per hour, and

(c) Employ good design and operation practices to limit emissions from the cooling towers.

D.1.14 Preventive Maintenance Plan [326 IAC 1-6-3]

The Preventive Maintenance Plan, in accordance with Section C - Preventive Maintenance Plan, of this permit, will include each combustion turbine and its associated emission control device.

Compliance Determination Requirements

D.1.15 Performance Testing

(a) Pursuant to 326 IAC 3-5 the Permittee shall conduct a performance test, within 60 days of achieving maximum production but no later than one-hundred and eighty days (180) after the facility startup or monitor installation, on the combustion turbine exhaust stack in order to certify the continuous emission monitoring systems for NO_X and CO.

(b) Within 60 days of achieving maximum production but no later than one hundred and eighty (180) days after initial startup, the Permittee shall perform a formaldehyde stack test for each combustion turbine stack utilizing a method approved by the commissioner when operating at 50%, 75% and 100% load and power augmentation mode. These tests shall be performed in accordance with Section C – Performance Testing, in order to demonstrate compliance with the formaldehyde emission limit specified in condition D.1.10.

(c) Within sixty (60) days of achieving maximum production rate, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall conduct NO_X and

SO_2 stack tests for each combustion turbine stack utilizing methods approved by the Commissioner. The Permittee can use alternative methods to determine compliance as specified in 40 CFR 60 Subpart GG. These tests shall be performed in accordance with 40 CFR 60.335 and Section C – Performance Testing, in order to document compliance with Condition D.1.4, D.1.6 (1) and D.1.8. In addition the Permittee shall utilize compliance provisions specified in 40 CFR 60 Subpart Da under 40 CFR 60.46a to show compliance with the NOx emissions limit in condition D.1.9 for the operation of duct burners.

(d) Within sixty (60) days of achieving maximum production rate, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall perform PM, VOC, H_2SO_4 mist and ammonia stack tests for each combustion turbine stack utilizing methods approved by the Commissioner. These tests shall be performed in accordance with 40 CFR 60.335, 40 CFR 60.48(a), and Section C – Performance Testing, in order to document compliance with D.1.1(a) and (b), D.1.9, D.1.7, D.1.6 (2) and D.1.11.

(e) IDEM, OAQ retains the authority under 326 IAC 2-1.1-8(f) to require the Permittee to perform additional and future compliance testing as necessary.

D.1.16 Oxides of Nitrogen NOx (SCR operation) [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD requirements), the Permittee shall determine the lowest optimum temperature of the catalyst bed during the stack test required in condition D.1.15 (a) (d) that demonstrates compliance with limits in condition D.1.4, as approved by IDEM.

(b) From the date of the valid stack test, during a startup, the Permittee shall measure and record temperature of the catalyst bed and start ammonia injection in the SCR units to control NOx emissions from the gas turbines, as soon as the catalyst bed reaches the temperature determined in part (a) above or turbine load reaches 50%, whichever occurs earlier.

D.1.17 40 CFR Part 60, Subpart GG Compliance Requirements (Stationary Gas Turbines)

Pursuant to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines), the Permittee shall monitor the nitrogen and sulfur content of the natural gas on a monthly basis as follows:

(a) Determine compliance with the nitrogen oxide and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a), per requirements described in 40 CFR 60.335(c);

(b) Determine the sulfur content of the natural gas being fired in the turbine by ASTM Methods D 1972-80, D 3031-81, D 4084-82, D 3246-81, or other applicable methods approved by IDEM. The applicable ranges of some ASTM methods mentioned are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator, and

(c) Determine the nitrogen content of the natural gas being fired in the turbine by using analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator.

The owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency may perform the analyses required above.

Owners, operators or fuel vendors may develop custom fuel schedules for determination of the nitrogen and sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. These schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with the above requirements.

D.1.18 Continuous Emission Monitoring (CEMs) [40 CFR 60 Subpart GG] [40 CFR 75] [326 IAC 3-5]

(a) The owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 326 IAC 2-2, shall be required to install a continuous emissions monitoring system.

(b) The Permittee shall install, calibrate, certify, operate and maintain a continuous emission monitoring system for NO_X and CO for stacks designated as 1 through 6 in accordance with 326 IAC 3-5-2 through 326 IAC 3-5-7.

(1) The continuous emission monitoring systems (CEMS) shall measure NO_X and CO emissions rates in pounds per hour and parts per million (ppmvd) corrected to 15% O_2. The use of CEMS to measure and record the NO_X and CO ppmvd limits, is sufficient to demonstrate compliance with the limitations established in the BACT analysis and set forth in the permit. To demonstrate compliance with the NO_X limits, the source shall take an average of the parts per million (ppm) corrected to 15% O_2 over a three (3) operating hour period. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) corrected to 15% O_2 over a twenty four (24) operating hour period. The source shall maintain records of the emissions parts per million and the pounds per hour.

(2) The Permittee shall determine compliance with Conditions D.1.4 and D.1.5 utilizing data from the NO_X, CO, and O_2 CEMS, the fuel flow meter, and Method 19 calculations.

(3) The Permittee shall submit to IDEM, OAQ, within ninety (90) days after monitor installation, a complete written Monitoring Plan, in accordance with the requirements of 40 CFR Part 75.

(4) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.

(c) Pursuant to 40 CFR 60.47(d), the Permittee shall install, calibrate, certify and operate continuous emissions monitors for carbon dioxide or oxygen at each location where nitrogen oxide emissions are monitored.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.1.19 Record Keeping Requirements [326 IAC 2-6.1-5 (a) (2)]

(a) To document compliance with Conditions D.1.1, and D.1.4 through D.1.7, the Permittee shall maintain records of the following:

(1) Amount of natural gas combusted (in MMCF) per turbine during each month.

(2) Percent sulfur of the natural gas.

(3) Heat input on a lower heating value basis of each turbine on a 30-day rolling average.

(b) To document compliance with Conditions D.1.4, D.1.5 and D.1.12, the Permittee shall maintain records of the following:

(1) The type of operation (i.e. startup or shutdown) with supporting operational data.

(2) The duration of all startup and shutdown events and total hours of startup and shutdown.

(3) The CEMS data, fuel flow meter data, and Method 19 calculations corresponding to each startup and shutdown period.

(c) To document compliance with Conditions D.1.4 and D.1.5, the Permittee shall maintain records of the emission rates of NO_X and CO in pounds per hour and parts per million (ppmvd) corrected to 15% oxygen.

(d) To document compliance with Condition D.1.17, the Permittee shall maintain records, including raw data of all monitoring data and supporting information, for a minimum of five (5) years from the date described in 326 IAC 3-5-7(a). The records shall include the information described in 326 IAC 3-5-7(b).

(e) To document compliance with Condition D.1.8, the Permittee shall maintain records of the natural gas analyses, including the sulfur and nitrogen content of the gas, for a period of three (3) years.

(f) All records shall be maintained in accordance with Section C – General Record Keeping Requirements, of this permit.

D.1.20 Reporting Requirements [326 IAC 2-6.1-5 (a) (2)]

The Permittee shall submit the following information on a quarterly basis:

(a) Records of excess NO_X and CO emissions (defined in 326 IAC 3-5-7 and 40 CFR Part 60.7) from the continuous emissions monitoring system. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C – General Reporting Requirements of this permit.

(b) The Permittee shall report periods of excess emissions, as required by 40 CFR 60.334(c).

(c) To document compliance with Condition D.1.12, a quarterly summary of the total number of startup and shutdown hours of operation shall be submitted to the address listed in Section C of this permit – General Reporting Requirements within thirty (30) days after the end of the quarter being reported.

SECTION D.2 FACILITY CONDITIONS – Auxiliary Boiler

Facility Description [326 IAC 2-5.1-3]:

One (1) auxiliary boiler, designated as Boil with maximum heat input rating of 40 MMBtu/hr, and exhausts to stack designated as BOIL 100.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.2.1 Particulate Matter Emissions (PM/PM_{10}) for Auxiliary Boiler [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the auxiliary boiler shall comply with the following:

(a) The PM and PM_{10} emissions each from the auxiliary boiler shall not exceed 0.0075 lb/MMBtu on a higher heating value basis and shall not exceed 0.3 pounds per hour.

(b) Use natural gas as the only fuel.

(c) Perform good combustion practices

D.2.3 Opacity Limitations [326 IAC 2-2]

Pursuant to 326 IAC 2-2, the Permittee shall not cause the average opacity of the auxiliary boiler stack to exceed twenty percent (20%) in any one (1) six (6) minute period.

D.2.4 Nitrogen Oxide (NO_X) Emission Limitations for Auxiliary Boiler [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements), the auxiliary boiler shall comply with the following:

(a) The NOx emissions from the auxiliary boiler shall not exceed 0.049 lb/MMBtu on a higher heating value basis and shall not exceed 1.9 pounds per hour.

(b) Use natural gas as the only fuel.

(c) Operate using low-NOx burners.

D.2.5 Carbon Monoxide (CO) Emission Limitations for Auxiliary Boiler [326 IAC 2-2]

Pursuant to 325 IAC 2-2 (PSD Requirements) the auxiliary boiler shall comply with the following:

(a) The CO emissions from the auxiliary boiler shall not exceed 0.082 lb/MMBtu on a higher heating value basis and shall not exceed 3.2 pounds per hour.

(b) Use natural gas as the only fuel.

(c) Operate utilizing good combustion practices.

D.2.6 Sulfur Dioxide (SO_2) Emission Limitations for Auxiliary Boiler [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the auxiliary boiler shall comply with the following:

(a) The SO_2 emissions from the auxiliary boiler shall not exceed 0.0006 lb/MMBtu on a higher heating value basis and shall not exceed 0.024 pounds per hour.

(b) Use natural gas with a sulfur content of less than or equal to 0.8 percent by weight, as the only fuel.

(c) Operate utilizing good combustion practices.

D.2.7 Volatile Organic Compound (VOC) Emission Limitations for Auxiliary Boiler [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the auxiliary boiler shall comply with the following:

(a) The VOC emissions from the auxiliary boiler shall not exceed 0.0054 lb/MMBtu on a higher heating value basis and shall not exceed 0.22 pounds per hour.

(b) Use natural gas as the only fuel.

(c) Operate using good combustion practices.

D.2.8 Natural Gas Limitations [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements), the natural gas usage from the auxiliary boiler shall not exceed 38.1 MMSCF per twelve (12) consecutive month period, rolled on monthly basis.

D.2.9 40 CFR Part 60 Subpart Dc (New Source Performance Standards for Small Industrial Commercial-Institutional Steam Generating Units)

Pursuant to New Source Performance Standards for Small Industrial Steam Generating Units the proposed auxiliary boiler is subject to the following requirements of Subpart Dc:

(a) Notification include the following information:

(1) The design heat input capacity, and to identify the types of fuels to be combusted.

(2) The anticipated annual operating hours based on each individual fuel fired.

(b) The owner or operator shall record and maintain records of the amounts of each fuel combusted during each day. All records required shall be maintained for a period of two (2) years following the date of such record.

D.2.10 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan in accordance with Section C of this permit - Preventive Maintenance Plan is required for the auxiliary boiler.

Compliance Determination Requirements

D.2.11 Performance Testing

(a) For compliance purposes auxiliary boiler emissions shall be calculated using the emission factors for small boilers with low NO_X burners in USEPA's AP-42 Section 1.4 (07/1998) and the measured heating value.

(b) IDEM, OAQ retains the authority under 326 IAC 2-1.1-8(f) to require the Permittee to perform additional and future compliance testing as necessary.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.2.12 Record Keeping Requirements [326 IAC 2-6.1-5 (a) (2)]

(a) To document compliance with Condition D.2.8, the Permittee shall maintain records of the amount of natural gas combusted for the auxiliary boiler during each month.

(b) All records shall be maintained in accordance with Section C – General Record Keeping Requirements.

D.2.13 Reporting Requirements [326 IAC 2-6.1-5 (a) (2)]

(a) The Permittee shall submit the following information on a quarterly basis: a summary of the information to document compliance with Condition D.2.8 shall be submitted to the addresses listed in Section C - General Reporting Requirements, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

(b) The natural gas boiler certification shall be submitted to the address listed in Section C - General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the six (6) month period being reported.

SECTION D.3 FACILITY CONDITIONS – Backup Equipment

Facility Description [326 IAC 2-5.1-3]:

(a) Six (6) black-start diesel generators, designated as BSG1 through BSG6, each with a maximum rated capacity of 19.1 MMBtu/hr HHV, utilizing low sulfur diesel fuel, and exhausting to stacks designated BSG-1 through BSG-6.

(b) One (1) diesel fire pump, designated as DFP-1, with a maximum rated capacity of 0.95 MMBtu/hr HHV utilizing low sulfur diesel fuel, and exhausts to stack designated as Fire Pump.

(c) One (1) emergency diesel generator, designated as AUG-1 with a maximum rated capacity of 10.1 MMBtu/hr HHV utilizing low sulfur diesel fuel, and exhausts to stack designated as Emergency.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.3.1 BACT Limitation for six (6) Black Start Generators [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the diesel fired six (6) Black Start Generators shall comply with the following:

(a) The total fuel input for each black start generator shall not exceed 94,733 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

(b) The sulfur content of the diesel fuel used in the black start generators shall be the lowest available in the commercial market and in no case to exceed 0.05 percent by weight.

(c) Perform good combustion practice.

D.3.2 BACT Limitation for Fire Pump [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the diesel fire pump shall comply with the following:

(a) The total fuel input for the fire pump shall not exceed 6,504 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

(b) The sulfur content of the diesel fuel used in the fire pump shall be the lowest available in the commercial market and in no case to exceed 0.05 percent by weight.

(c) Perform good combustion practice.

D.3.3 BACT Limitation for Emergency Generator [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the emergency generator shall comply with the following:

(a) The total fuel input for the emergency generator shall not exceed 23,683 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

(b) The sulfur content of the diesel fuel used in the emergency generator shall be the lowest available in the commercial market and in no case to exceed 0.05 percent by weight.

(c) Perform good combustion practice.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.3.4 Record Keeping Requirements [326 IAC 2-6.1-5 (a) (2)]

To document compliance with Conditions D.3.1 through D.3.3, the Permittee shall maintain records of the following:

(1) Amount of diesel fuel combusted each month in each black start generator.

(2) Amount of diesel fuel combusted each month in the fire pump.

(3) Amount of diesel fuel combusted each month in the emergency generator.

(4) The percent sulfur content of the diesel fuel.

D.3.5 Reporting Requirements [326 IAC 2-6.1-5 (a) (2)]

A quarterly summary of the information to document compliance with D.3.1 through D.3.3 shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

MALFUNCTION REPORT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
FAX NUMBER - 317 233-5967

This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.

THIS FACILITY MEETS THE APPLICABILITY REQUIREMENTS BECAUSE IT HAS POTENTIAL TO EMIT 25 LBS/HR PARTICULATE MATTER ?_____, 100 LBS/HR VOC ?_____, 100 LBS/HR SULFUR DIOXIDE ?_____ OR 2000 LBS/HR OF ANY OTHER POLLUTANT ?_____ EMISSIONS FROM MALFUNCTIONING CONTROL EQUIPMENT OR PROCESS EQUIPMENT CAUSED EMISSIONS IN EXCESS OF APPLICABLE LIMITATION ________.

THIS MALFUNCTION RESULTED IN A VIOLATION OF: 326 IAC _______ OR, PERMIT CONDITION # _______ AND/OR PERMIT LIMIT OF _______________

THIS INCIDENT MEETS THE DEFINITION OF 'MALFUNCTION' AS LISTED ON REVERSE SIDE ? Y N

THIS MALFUNCTION IS OR WILL BE LONGER THAN THE ONE (1) HOUR REPORTING REQUIREMENT ? Y N

COMPANY:____PHONE NO. ( )________________
LOCATION: (CITY AND COUNTY)____
PERMIT NO. _____________ AFS PLANT ID: _____________ AFS POINT ID: _____________ INSP:________
CONTROL/PROCESS DEVICE THAT MALFUNCTIONED AND REASON:________________________________
____

DATE/TIME MALFUNCTION STARTED: _____/_____/ 20____ ________________________________ AM / PM

ESTIMATED HOURS OF OPERATION WITH MALFUNCTION CONDITION: ____________________________________

DATE/TIME CONTROL EQUIPMENT BACK-IN SERVICE______/______/ 20____ _______________ AM/PM

TYPE OF POLLUTANTS EMITTED: TSP, PM-10, SO2, VOC, OTHER:________________________________

ESTIMATED AMOUNT OF POLLUTANT EMITTED DURING MALFUNCTION: ______________________________
____

MEASURES TAKEN TO MINIMIZE EMISSIONS:____
____

REASONS WHY FACILITY CANNOT BE SHUTDOWN DURING REPAIRS:

CONTINUED OPERATION REQUIRED TO PROVIDE ESSENTIAL* SERVICES:______________________________
CONTINUED OPERATION NECESSARY TO PREVENT INJURY TO PERSONS:______________________________
CONTINUED OPERATION NECESSARY TO PREVENT SEVERE DAMAGE TO EQUIPMENT:____________________
INTERIM CONTROL MEASURES: (IF APPLICABLE)____
____
____

MALFUNCTION REPORTED BY:__________________________TITLE:______________________
(SIGNATURE IF FAXED)

MALFUNCTION RECORDED BY:_________________DATE:_____________TIME:_____________

Please note - This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.

326 IAC 1-6-1 Applicability of rule

Sec. 1. This rule applies to the owner or operator of any facility required to obtain a permit under 326 IAC 2-5.1 or 326 IAC 2-6.1.

326 IAC 1-2-39 "Malfunction" definition

Sec. 39. Any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner.

***Essential services** are interpreted to mean those operations, such as, the providing of electricity by power plants. Continued operation solely for the economic benefit of the owner or operator shall not be sufficient reason why a facility cannot be shutdown during a control equipment shutdown.

If this item is checked on the front, please explain rationale:

____

____

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: Tenaska Indiana Partners L.P.
Location: County Road 625 East, Otwell, IN 47564
Permit No.: CP-125-12760-00039
Source: Auxiliary Boiler
Limit: 38.1 MMCF per twelve (12) consecutive month period

Year: ____________

Month	Column 1 Usage (MMCF/month)	Column 2 Usage for previous 11 month(s) (MMCF)	Column 1 + Column 2 Usage for twelve month period (MMCF)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ____________________
Title / Position: ____________________
Signature: ____________________
Date: ____________________
Phone: ____________________

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: Tenaska Indiana Partners L.P.
Location: County Road 625 East, Otwell, IN 47564
Permit No.: CP-125-12760-00039
Source: Black Start Generators – (six (6) in number, please copy and use separate form for each generator).
Limit: 94,733 gallons per twelve (12) consecutive month period

Year: ____________
Generator ID:_________

Month	Column 1 Diesel Fuel Oil Usage (gallons/month)	Column 2 Diesel Fuel Oil Usage for previous 11 month(s) (gallons)	Column 1 + Column 2 Diesel Fuel Oil Usage for twelve month period (gallons)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: Tenaska Indiana Partners L.P.
Location: County Road 625 East, Otwell, IN 47564
Permit No.: CP-125-12760-00039
Source: Emergency diesel fire pump
Limit: 6504 gallons per twelve (12) consecutive month period

Year: ____________

Month	Column 1 Diesel Fuel Oil Usage (gallons/month)	Column 2 Diesel Fuel Oil Usage for previous 11 month(s) (gallons)	Column 1 + Column 2 Diesel Fuel Oil Usage for twelve month period (gallons)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________
Title / Position: ______________________
Signature: ______________________
Date: ______________________
Phone: ______________________

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: Tenaska Indiana Partners L.P.
Location: County Road 625 East, Otwell, IN 47564
Permit No.: CP-125-12760-00039
Source: Emergency generator
Limit: 23,683 gallons per twelve (12) consecutive month period

Year: ____________

Month	Column 1 Diesel Fuel Oil Usage (gallons/month)	Column 2 Diesel Fuel Oil Usage for previous 11 month(s) (gallons)	Column 1 + Column 2 Diesel Fuel Oil Usage for twelve month period (gallons)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: Tenaska Indiana Partners L.P.
Location: County Road 625 East, Otwell, IN 47564
Permit No.: CP-125-12760-00039
Source: natural gas combustion turbines each operating in combined cycle (six (6) in number, please copy and use separate form for each turbine).
Limit: 650 hours for startup and shutdown in a 12 consecutive month period rolled on monthly basis

Year: ____________
Turbine ID: __________

Month	Column 1 hours during startup and shutdown this month	Column 2 hours during startup and shutdown during previous 11 months	Column 1 + Column 2 hours during startup and shutdown for twelve month period
	Hours	Hours	Hours

No deviation occurred in this month

Deviation/s occurred in this month.
Deviation has been reported on:

Submitted by: ______________________________
Title/Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

SEMI-ANNUAL NATURAL GAS FIRED BOILER CERTIFICATION

Company Name: Tenaska Indiana Partners L.P.
Location: County Road 625 East, Otwell, IN 47564
Permit No.: CP-125-12760-00039

9 Natural Gas Only **9** Alternate Fuel burned From:_____________ To:_____________

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
Signature:
Printed Name:
Title/Position:
Phone:
Date:

A certification by the responsible official as defined by 326 IAC 2-7-1(34) is required for this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

SEMI-ANNUAL DEVIATION AND COMPLIANCE MONITORING REPORT

Company Name: Tenaska Indiana Partners L.P.
Location: County Road 625 East, Otwell, IN 47564
Mailing Address: 1044 N.115 Street, Suite 400, Omaha NE 68154
Permit No.: CP-125-12760-00039

Months: ___________ **to** ____________ **Year:** ______________

Page 1 of 2

This report shall be submitted semi-annually based on a calendar year. Any deviation from the requirements, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. Deviations that are required to be reported by an applicable requirement shall be reported according to the schedule stated in the applicable requirement and do not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".	
NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.	
THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Form Completed By:

Title/Position:

Date:

Phone:

Attach a signed certification to complete this report.

Mail to: Permit Administration & Development Section
Office of Air Quality
100 North Senate Avenue
P. O. Box 6015
Indianapolis, Indiana 46206-6015

Tenaska Indiana Partners, L.P.
1044 N.115 Street, Suite 400,
Omaha NE 68154

Affidavit of Construction

I, ______________________________, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in ____________________ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of ________________ for ________________.
(Title) (Company Name)

3. By virtue of my position with ______________________,I have personal
(Company Name)

knowledge of the representations contained in this affidavit and am authorized to make

these representations on behalf of ______________________________ .
(Company Name)

4. I hereby certify that Tenaska Indiana Partners, L.P., County Road 625 East, Otwell, IN 47564, completed construction of the natural gas power plant on ______________in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality and as permitted pursuant to **Construction Permit No. CP-125-12760, Plant ID No. 125-00039** issued on ______________

5. I hereby certify that Tenaska Indiana Parterres, L.P. is now subject to the Title V program and will submit a Title V operating permit application within twelve (12) months from the postmarked submission date of this Affidavit of Construction.

Further Affiant said not.

I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

____
Signature

____
Date

STATE OF INDIANA)
)SS

COUNTY OF ______________)

Subscribed and sworn to me, a notary public in and for ________________ County and State of Indiana

on this ____________ day of ______________, 20 _______ .

My Commission expires: ________________

____
Signature

____
Name (typed or printed)

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the
Technical Support Document for New Construction and Prevention of Significant Deterioration Permit

Source Background and Description

Source Name:	Tenaska Indiana Partners, L.P.
Source Location:	County Road 625 East, Otwell, IN 47564
County:	Pike
Construction Permit No.:	CP-125-12760-00039
SIC Code:	4911
Permit Reviewer:	Gurinder Saini

On June 27, 2002, the Office of Air Quality (OAQ) had a notice published in the Press-Dispatch, Petersburg, Indiana, stating that Tenaska Indiana Partners, L.P., had applied for an approval to construct and operate an 1800 MW natural-gas-fired combined-cycle power plant, Tenaska Indiana Generating Station. The public notice also stated that the IDEM, OAQ proposed to issue the PSD permit for this operation and provided information on how the public could review the proposed approval and other documentation. Finally, the notice informed interested parties that there was a period till July 30, 2002 to provide comments on the draft permit.

On October 24, 2002, the IDEM, OAQ discussed the matter of installation of Oxidation Catalyst to control Carbon Monoxide (CO), Volatile Organic Compounds (VOC) and Formaldehyde emissions for the six combined cycle combustion turbine with the applicant. The applicant agreed to install and operate the oxidation catalyst (the top CO and VOC control identified as part of the top down BACT analysis in the Appendix C of the TSD) and lower the CO emission limit. The conditions D.1.5 and D.1.6 of the permit are changed as follows:

D.1.5 Carbon Monoxide (CO) Emission Limitations for Combustion Turbines/Duct Burners[326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), each combustion turbine/steam generating unit shall comply with the following, excluding startup and shutdown periods:

(1) During ~~normal~~ combined-cycle operation **at loads greater than 65 %** ~~(fifty (50) percent load or more)~~, the CO emissions from each combustion turbine shall not exceed ~~6~~ **3.6** ppmvd corrected to fifteen (15) percent oxygen, averaged on a 24-operating hour period and shall not exceed ~~27.8~~ **16.7** pounds per hour.

(2) During combined-cycle operation at loads greater than 50 % and less than or equal to 65%, the CO emissions from each combustion turbine shall not exceed 6 ppmvd corrected to fifteen (15) percent oxygen, averaged on a 24-operating hour period and shall not exceed 27.8 pounds per hour.

(~~2~~**3**) During normal operation (fifty (50) percent load or more), the CO emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed ~~9~~ **5.4** ppmvd corrected to fifteen (15) percent oxygen, based on a 24-operating hour period and shall not exceed ~~52.8~~ **31.7** pounds per hour.

(~~3~~**4**) During power augmentation mode, the CO emissions from each combustion turbine stack shall not exceed ~~53~~ **11** ppm corrected to fifteen (15) percent oxygen, averaged on a 24-operating hour basis and shall not exceed ~~290.6~~ **60.3** pounds per hour for each combustion turbine and duct burner.

(b)~~(4)~~ The duct burners shall not be operated until normal combined cycle operation begins.

(c)~~(5)~~ Good combustion practices shall be applied to minimize CO emissions.

(d)~~(6)~~ Use natural gas as the only fuel.

(e)~~(7)~~ **An oxidation catalyst system shall be installed and operated at all times to control CO emissions when the combustion turbines are operating.** ~~From the date of start of commercial operation of combined cycle combustion turbines, the facility will have 6 months to evaluate the ability to achieve a CO limit of 6 ppmvd at 15% O_2 averaged on a 24-operating hour period, without an oxidation catalyst. If this limit cannot be achieved after the 6 months evaluation period, the facility shall have 18 months from the date of the start of commercial operation of combined cycle combustion turbines to install an oxidation catalyst and demonstrate compliance with the specified CO emission limits.~~

(f)~~(b)~~ Pursuant to 326 IAC 2-2 (PSD Requirements), the annual CO emission from each combustion turbine and associated duct burner, excluding startup and shutdown emissions, shall not exceed ~~190~~ **74.2** tons per year.

D.1.7 Volatile Organic Compound (VOC) Emission Limitations for Combustion Turbines/Duct Burners [326 IAC 2-2] [326 IAC 8-1-6]

Pursuant to 326 IAC 8-1-6 (VOC Requirements) and 326 IAC 2-2 (PSD Requirements), the following requirements must be met:

(1) The VOC emissions from each combustion turbine shall not exceed 0.0015 pounds per MMBtu (higher heating value basis) and shall not exceed 1.6 pounds per hour.

(2) The VOC emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 0.0051 pounds per MMBtu (higher heating value basis) and shall not exceed 12.1 pounds per hour.

(3) During the power augmentation mode, the VOC emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 0.01 pounds per MMBtu (higher heating value basis) and shall not exceed 15.3 pounds per hour.

(4) The use of natural gas as the only fuel.

(5) Good combustion practice shall be implemented **and oxidation catalyst be installed and operated** to minimize VOC emissions.

The VOC emission limits in the above condition already take into account the use of oxidation catalyst with up to 50% reduction in the VOC emissions. Therefore, these limits are left unchanged in the permit.

Written comments were received from Mr. Stephen Loeschner of Fort Wayne, Indiana, on July 26, 2002. These comments and IDEM, OAQ responses, including changes to the permit (where language deleted is shown with strikeout and that added is shown in bold) are as follows:

General overview by the Commentator:

This is comment on a draft Prevention of Significant Deterioration ("PSD") permit for Tenaska Indiana Partners, L.P. ("TIP") to construct and operate the Tenaska Indiana Generating Station

("TGS") in Pike County, Indiana as described in Indiana Department of Environmental Management ("DEM") draft permit document package 125- 12760- 00039 ("12760") consisting of: 1) six 2,112 maximum million BTU ("MBTU") per hour ("hr") generic natural gas fired combustion turbines ("CT"), 2) six 550 maximum rated MBTU / hr generic natural gas fired duct burners, 3) one 40 maximum rated MBTU / hr generic natural gas fired boiler, 4) six 19.1 maximum rated MBTU / hr oil fired diesel engine electric generating sets, 5) one 10.1 MBTU / hr oil fired diesel engine electric generating set, 6) one 0.95 MBTU / hr oil fired diesel engine firewater pump, and 7) two cooling towers. Higher heating value BTU is assumed throughout this comment.

This comment totally replaces my 19 July 2002 comment.

Comment 1:

<u>Sulfur dioxide Best Available Control Technology and federal enforceability</u>
With 12760 Conditions D.1.6(1) and D.1.15(c) DEM has placed various limits on TGS sulfur ("S") dioxide ("SO2") emission, and in the narrative Best Available Control Technology ("BACT," a clever legal term wherein best does not mean best, see 42 USC 7479(3), 40 CFR 52.21(b)(12)) text of Appendix C to the 12760 Technical Support Document ("TSD"), DEM alleges that it has properly selected BACT.

"... [N]atural gas has a low sulfur content (typically less than 2 grains sulfur per standard cubic foot of gas). [sic] ... The use of low sulfur fuels was the next level of control that was evaluated. *Natural gas has the lowest sulfur content of all the fossil fuels.* ... [B]ACT shall be the use of low sulfur natural gas...." (12760 TSD Appendix C pp. 17-18, emphasis added)

Since DEM did not cite law or regulation as to what its "natural gas" is, its statements are not bounded. In fact TGS is subject to the 40 CFR 72 Acid Rain regulations, and as such the 40 CFR 72.2 definitions reasonably apply. In fact the 12760 Conditions D.1.6(1) and D.1.15(c) resemble "40 CFR 72.2 *natural gas*." In fact DEM's assertion that it was diligent in exploring low S fuel as BACT is callously false for DEM's "natural gas" has approximately 3.3 times the S content of "40 CFR 72.2 *pipeline natural gas*," which DEM did not consider. That failure is clear error, and DEM must require "40 CFR 72.2 *pipeline natural gas*" as BACT.

To assure that SO2 limits are 40 CFR 52.21(b)(17) federally enforceable ("federally enforceable") on a more or less continuous basis where continuous, quantitative measurements of the regulated pollutant are infeasible, surrogate parameters must be expressed in the permit. While the USC and CFR are somewhat lacking in re the specifics of the discretion that DEM may apply to the case, the U.S. Environmental Protection Agency ("EPA") published an October 1990 draft *New Source Review Workshop Manual* ("WM" incorporated herein by reference) which has been held in rather high regard by the U.S. Environmental Appeals Board. The WM mentions such surrogacy on p. H.4, Table H.1; p. H.6 middle para.; and p. H.7, H.8, H.10, I.3, I.4, and I.6. The WM p. H.6 language is the strongest, "Where continuous, quantitative measurements [of the pollutant] are infeasible, surrogate parameters *must* be expressed in the permit" (emphasis added). Conditions include periodic stack testing of the regulated SO2 pollutant and periodic fuel testing for total S content.

It is entirely practical and economical to perform a fuel test with methods that yield results that are at least 20 times higher than the minimum detection level for total S on a monthly basis. Nothing less stringent than such, coupled with a limit of 0.6 grains total S per 100 standard cubic feet of fuel, must be incorporated into the amended draft prior to issuance for all of the natural gas fired equipment.

DEM has equal responsibility for applying BACT to the oil fired equipment. There is no economic or availability discussion whatsoever in Appendix C to the 12760 TSD as to how DEM arrived at 500 parts per million by weight ("ppmw") total S in oil. In fact, fuel oil having no more than 50 ppmw total S is readily available. DEM must incorporate fuel oil having no more than 50 ppmw total S together with tests of delivered fuel into the amended draft prior to issuance for all of the oil fired equipment.

Response 1:

Tenaska Indiana Generating Station is an affected unit under 40 CFR 72. The IDEM, OAQ has changed the condition D.1.6 to clarify that the natural gas proposed to be used shall be pipeline quality only. The IDEM, OAQ has revised the grains limit in this condition as follows:

D.1.6 Sulfur Dioxide (SO_2) and H_2SO_4 mist Emission Limitations for Combustion Turbines/Duct Burners [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements), each combustion turbine and duct burner shall comply with the following:

(1) During normal combined-cycle operation (fifty (50) percent load or more), the SO_2 emissions from each combustion turbine and duct burner shall not exceed 0.0055 pounds per MMBtu (higher heating value basis) and shall not exceed 14.7 pounds per hour.

(2) During normal combined-cycle operation (fifty (50) percent load or more), the H_2SO_4 mist emissions from each combustion turbine and duct burner shall not exceed 0.0034 lb/MMBtu (higher heating value basis) and shall not exceed 8.1 pounds per hour.

(3) The use of **pipeline** natural gas as the only fuel for the combustion turbines and duct burners. The sulfur content of the natural gas shall not exceed ~~0.007 percent by weight (two (2)~~ **0.6** grains per 100 scf as defined in 40 CFR 72.~~)~~.

(4) Perform good combustion practice.

The condition D.1.17 of the permit requires the Permittee to determine sulfur content of the natural gas once every month. Therefore no additional monitoring requirements for sulfur content are added here. The ASTM test methods specified in this requirement for determining sulfur content are part of 40 CFR 60 Subpart GG and are applicable to this Source. If required alternative methods can be specified and approved by IDEM, OAQ for this source.

The diesel fired equipment at this source is limited on hours of operation. The “low sulfur” diesel fuel is not yet commercially available in Indiana. As and when the low sulfur fuel will be available, the Permittee will be required to use the same in the backup equipment at this plant. The conditions D.3.1, D.3.2 and D.3.3 are changed to correctly reference the units, and to indicate that the Permittee shall use the lowest sulfur content diesel fuel available as follows:

D.3.1 BACT Limitation for six (6) Black Start Generators [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the diesel fired six (6) Black Start Generators shall comply with the following:

(a) The total fuel input for each black start generator shall not exceed 94,733 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

(b) The sulfur content of the diesel fuel used ~~by~~ **in** the ~~fire pump~~ **black start generators** shall **be the lowest available in the commercial market and in no case to** ~~not~~ exceed 0.05 percent by weight.

(c) Perform good combustion practice.

D.3.2 BACT Limitation for Fire Pump [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the diesel fire pump shall comply with the following:

(a) The total fuel input for the fire pump shall not exceed 6,504 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

(b) The sulfur content of the diesel fuel used ~~by~~ **in** the fire pump shall **be the lowest available in the commercial market and in no case to** ~~not~~ exceed 0.05 percent by weight.

(c) Perform good combustion practice.

D.3.3 BACT Limitation for Emergency Generator [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the emergency generator shall comply with the following:

(a) The total fuel input for the emergency generator shall not exceed 23,683 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

(b) The sulfur content of the diesel fuel used ~~by~~ **in** the emergency generator shall **be the lowest available in the commercial market and in no case to** ~~not~~ exceed 0.05 percent by weight.

(c) Perform good combustion practice.

Comment 2:

Formaldehyde minor status

Nothing in the law or regulation permits a source to be permitted as a minor source and yet emit major amounts. Month after month Whiting Clean Energy, 089- 11194- 00449 (“Whiting”), evaded its “180-day” formaldehyde (“HCHO”) D.1.13(a)(4) test obligation (its entire record is incorporated herein by reference). There is no reason to believe DEM would be diligent in enforcement of 12760 Condition D.1.15(b). Conditions must be added that when the HCHO is found to exceed 160 pounds per trillion BTU (“TBTU”), that operation must be curtailed such that in any given continuous 365-day period the product of the rate times the fuel used is less than 10 tons and that all measurement uncertainties shall be added to the calculated amount prior to comparison to the 10 ton limit.

Response 2:

The condition D.1.10(b) of the permit requires the Permittee to install oxidation catalyst. The condition D.1.10 is changed as follows:

D.1.10 Formaldehyde Limitations [326 IAC 2-4.1-1]

~~(a)~~ The formaldehyde emission from the combined cycle combustion turbines shall not exceed 0.00016 lb/MMBtu. This shall limit the formaldehyde emissions from the entire source to less than ten (10) tons per year and make requirements of 326 IAC 2-4.1 not applicable. Any increase in single Hazardous Air Pollutant (HAP) emissions greater than the threshold specified above and combined HAPs greater than twenty five (25) tons per year, from the entire Source must be approved by the Office of Air Quality (OAQ) before such change may occur.

~~(b) From the date of start of commercial operation of combined cycle combustion turbines, the facility will have 6 months to evaluate the ability to achieve the Formaldehyde limit of 0.00016 lb/MMBtu, without an oxidation catalyst. If this limit cannot be achieved after the 6 months evaluation period, the facility will have 18 months from the date of the start of commercial operation of combined cycle combustion turbines to install an oxidation catalyst and demonstrate compliance with the specified limit.~~

Comment 3:

Formaldehyde validity
DEM's language of 12760 Condition D.1.15(b) "method approved by the commissioner" is of no comfort because the commissioner has delegated that decision to people dedicated to not obtaining meaningful data. In the case of Whiting, it is my understanding that their HCHO tests resulted in "below the level of detection." If my understanding is correct, then that is non-science. HCHO tests on DPL, 179- 12321- 00026 ("DPL"), produced single digit (and that digit may not be significant) raw results at the analysis of liquid lab sample level (its entire record is incorporated herein by reference). DEM staff, given authority by the commissioner, translated this raw data: "3., 1., 1.; 2., 2., 1.; 2., 3., 1.; 1., 1., 2.; 1., 2., 6.; 5., 4., 4." (three test runs on two turbines operating at three power levels) into these results: "624.; 580.; 855.; 498.; 1,508.; 2,029.;" and DEM never bothered to tell that its 3- and 4-digit results had no basis in sound science whatsoever.

It may be some time before HCHO continuous emission monitoring ("CEM") becomes physically and economically practical. Thus to have some concept of how much HCHO is dumped in the air some surrogacy is needed. Carbon monoxide ("CO") provides some. For HCHO testing to have value there needs to be a collection of many items of coincident data: 1) pounds mass of HCHO per TBTU, 2) pounds mass of CO per TBTU, 3) turbine model detail, 4) MBTU / hr fuel input, 5) net generated megawatts ("MW") electrical power, 6) percentage of nominal MW for the specific relative humidity and temperature of the ambient air, 7) the relative humidity and temperature of the ambient air. Some of those elements are absent from the DPL tests.

Further, the minimum sensitivity of the test (all chemical results to be at least 20 times the minimum detection level) must be specified in the permit and not left to inappropriately placed discretion. Additionally, the chemical tests must not bump into a saturation. I.e. if there is an average measured result of Ra for a C concentration and an average measured result of Rb for a 2 x C concentration, then Rb must be at least 1.9 x Ra.

I am not interested in receiving an excuse that there is no adequate HCHO test in combustion stack gas or total S in fuel gas test in 40 CFR 60, 40 CFR 63, or elsewhere within or referenced in the 40 CFR umbrella. The fact is we (the U.S. and the rest of the world), now routinely chemically test gasses in rather fine detail, for example less than 1 nanogram per dry standard cubic meter (See Dioxins in Table 1 to 40 CFR 60 Subpart CCCC at end of 40 CFR 60.2265 for example). As I understand it, that example is more sensitive than 400 parts per quadrillion on a weight basis and that it is more sensitive than 50 parts per quadrillion on a volume basis. Analytical chemistry equipment and human talent is available to do the job and I expect that it be required without exception no matter that there may not be a precisely defined EPA test method associated with it. Quantifying rather accurately several micrograms of HCHO in a dry standard cubic meter of combustion stack gas should be rather doable.

Response 3:

The IDEM, OAQ established a formaldehyde limit in the permit for Whiting Clean Energy based on the vendor specification for the combustion turbines, to maintain the minor status for the applicability of case-by-case Maximum Achievable Control Technology under Section 112 (g) of the Clean Air Act. Based on the calculations for the worst case emissions, the Source had formaldehyde emissions below 10 tons per year. Based on the IDEM, OAQ internal guidance document with respect to the stack testing procedure, the Permittee was required to test these units to show that when built, these units have emissions less than the vendor specifications used in the permit calculations.

Irrespective of the "level of detection", the purpose of the test is to establish the minor status for HAP emissions, by verifying, that the emissions rate is below the emission rate stated in the application for the permit and the permit itself for the formaldehyde. In the case of Whiting test, the IDEM, OAQ may not have established with certainty the quantity of the actual emissions of formaldehyde. This is because the formaldehyde emissions observed during the test, using the test method approved by IDEM, OAQ, were "below detectable level". This ensures that the emissions are at least 5 times below the limit contained in the permit. The detection level in the test method was at 0.0001 lb/MMBtu and the permit limit for the formaldehyde emissions is 0.0005 lb/MMBtu.

Based on above, the annual worst-case formaldehyde emissions can be calculated as follows:

$$\frac{0.0001\ \text{lb}}{\text{MMBtu}} \times \frac{1735\ \text{MMBtu}}{\text{hour}} \times \frac{8760\ \text{hours}}{\text{year}} \times \frac{0.0005\ \text{lb}}{\text{ton}} = \frac{0.75\ \text{tons}}{\text{year}}$$

The source has two turbines = 2 X 0.75 = 1.5 tons per year

This is much below the applicability threshold for the case-by-case Maximum Achievable Control Technology requirements under section 112 (g) of the Clean Air Act.

The IDEM, OAQ prefers to specify the test methods for the performance test at the time the Permittee submits the test protocol as part of the procedure to conduct performance stack testing. This allows the IDEM, OAQ to specify the latest developed test methods (which are usually more accurate, because the performance test is carried out usually more than a year after the permit issuance on the startup of the new facility) available at the time of the test to be utilized in the stack test. The commentator's concerns about the formaldehyde emissions limit in permit at 0.00016 lb/MMBtu being to close to the test method detection level has merit. While evaluating the selection of the test methods in the testing protocol submitted by the Permittee, the IDEM, OAQ makes sure that adequate margin is available between the permit limit and the detection level for the test method. Unlike as suggested by the commentator, it is not always feasible or viable to discard a test method because the detection level is not sufficiently (20 times as suggested by the commentator) below the permit limit. The idea of the limit is to establish the minor status for section 112 (g) of the Clean Air Act. The IDEM, OAQ consults with U.S. EPA and other state and local agencies to identify suitable test methods for pollutants such as formaldehyde for which no EPA approved test methods exist at the moment.

To further verify the formaldehyde minor status, the Permittee will be required to test and confirm the formaldehyde emission rate during power augmentation mode also. This change in condition D.1.15 is shown below:

D.1.15 Performance Testing

(a) Pursuant to 326 IAC 3-5 the Permittee shall conduct a performance test, no later than one-hundred and eighty days (180) after the facility startup or monitor installation, on the combustion turbine exhaust stack in order to certify the continuous emission monitoring systems for NO_X and CO.

(b) Within one hundred and eighty (180) days after initial startup, the Permittee shall perform a formaldehyde stack test for each combustion turbine stack utilizing a method approved by the commissioner when operating at 50%, 75% and 100% load **and power augmentation mode**. These tests shall be performed in accordance with Section C – Performance Testing, in order to verify the formaldehyde emission factor specified in condition D.1.10.

There are other changes in condition D.1.15 that are shown on the following pages. This change will be implemented in that condition D.1.15 as normal text.

Comment 4:

Formaldehyde minor status sham
DEM alleges its 12760 Condition D.1.10 would make TGS minor, and that would be likely be true

if it was applied as stated in that paragraph. In fact there is no aggregation of the HCHO produced in start-up and shutdown ("SU/SD") in any test whatsoever. HCHO, like carbon monoxide ("CO"), is a product of incomplete combustion that becomes a large pollutant during SU/SD. In 12760 Condition D.1.5(b)(1), DEM allows a turbine a 190 ton per year ("tpy") CO emission (and that includes the duct burner), while in 12760 Conditions D.1.12(c) and (d) the turbine is allowed approximately: 13,558 / 2,000 x 650 / 5.6 = 787 tpy CO for SU/SD. The relationship of CO to HCHO is in the same direction and there is every reason to believe that the 12760 draft, even with an enforced HCHO test at 50% power, would permit the TGS turbines to emit vastly more HCHO that the synthetic minor of 10 tpy as a result of SU/SD. Precisely the same applies to DEM's gifts to TGS in re power augmentation in 12860 Conditions D.1.3 and D.1.5(a)(3) as during that operating mode the HCHO emission, like CO, will increase considerable and it will no doubt make the total TGS emission vastly more than 10 tpy.

Response 4:

The emissions of Hazardous Air Pollutants (HAPs) and especially formaldehyde vary tremendously depending upon type (size) of turbine and the type of combustor being used. The ambient temperature and the ramp up duration for the combustion turbine in the combined cycle mode can also affect the emissions. In a memo[1] from U.S. EPA, it is stated "The EPA recently received and analyzed new emissions test data for 8 tests for formaldehyde on lean premix stationary combustion turbines. The tests were conducted on lean premix stationary combustion turbines ranging in size from 10 MW to 170 MW. The average formaldehyde emission factor for high (> 80 percent) loads from these tests is 6.49 E –05 lb/MMBtu. The 95th percentile level is 2.02 E –04 lb/MMBtu. The 95th upper percentile emission factor may be more appropriate to use for determining whether a source is major since it considers the test result variability. Comparison of these emission factors to emissions factors for diffusion flame stationary combustion turbines equipped with oxidation catalyst systems shows that HAP emission factors from lean premix stationary combustion turbines are equivalent or lower than HAP emissions from diffusion flame stationary combustion turbines equipped with oxidation catalyst systems. Thus *lean premix combustion is a comparable technology to oxidation catalyst systems*.[emphasis added]"

It is also stated in the same memo that the proper performance of lean premix combustor indicated by low NOx emissions would in turn assure low HAP emissions.

In case of operation of the combined cycle combustion turbine, there are three types of startups. These are: hot, warm and cold. These startup scenarios are as follows:

Hot Start: duration up to one hour, following a shutdown less than or equal to 8 hours;
Warm Start: duration up to two hours, following a shutdown between 8 and 48 hours;
Cold Start: duration up to four hours, following a shutdown greater than 48 hours.

The commentator's main concern is the cold start, which can last up to 4 hours. During the cold start the turbine is ramped up to 10% load and held there for some period while the HRSG is heating up. Once the HRSG heats up the normal operation can start.

In reply to the commentator's argument the IDEM, OAQ points out the following:

1. As explained in Sims Roy memo, NOx emissions are more appropriate surrogate for formaldehyde emissions for lean premix type combustors.

2. The commentator compared the CO emissions at full load and part load (startup and shutdown) conditions. Based on that the commentator's estimated 4 times increase in formaldehyde emissions during low load (<50%) operation than full load (>80%) operation. This argument is highly speculative and non-confirmatory in nature.

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[1] Memorandum by Sims Roy of Emission Standards Division, Combustion Group, US EPA, dated August 21, 2001

3. Based on the above and Sims Roy memo, this proportion should be calculated based on increase in NOx emissions rather than CO during the cold startup.

4. The uncontrolled NOx emissions at full load from 501F turbine are less than 5216 tons per year (Appendix A – Emission Calculations - page 2 of 10 of TSD). The NOx emissions during the startup and shutdown (SU&SD) are less than the following:

   NOx emissions during startup and shutdown =

   $$\frac{827\text{ lb of NOx}}{\text{SU\&SD}} \times \frac{650\text{ hours SU\&SD}}{\text{year}} \times \frac{1\text{ SU\&SD}}{5.6\text{ hours}} \times \frac{1\text{ ton}}{2000\text{ lb}}$$

   = 48 tons per year

   Therefore, during low load conditions, NOx emissions are a very small fraction of the emissions during the normal operation.

5. IDEM disagrees with the commentator's comparison of emissions on an annual basis because of difference in hours of operation under each load condition. A more appropriate comparison would be the short term emission rate in terms of lb/hour. This comparison is shown below:

   NOx Emissions from the operation of the turbine under normal conditions = 191 lb/hour

   NOx Emissions from the operation of the turbine under startup conditions (worst case) =

   $$\frac{778\text{ lb of NOx}}{\text{startup}} \times \frac{1\text{ startup}}{4.95\text{ hours}} = 157\text{ lb/hour}$$

   The above calculation is based on a hypothetical case that the emissions during startup are distributed evenly for the entire duration of startup. In reality the emissions are proportional to the heat input rate and the load on the turbine. Therefore, the emissions increase as the turbine ramps up to the full load. The above comparison shows that the emissions during normal operation and SU/SD are more or less in similar range.

6. By definition, each cold start is preceded by at least 48 hours of no operation. Therefore, for each 4 hours of high formaldehyde emissions during a cold start, there will be a 48 hour period of no formaldehyde emissions. This balances out the formaldehyde emissions for the long term (annual basis) operation. In addition, this power plant is a base load type unit (not a peaking unit), and will not encounter frequent shutdowns and startups.

7. The estimated formaldehyde emissions from the combustion turbine are 7.56 tons per year. Therefore, the OAQ, IDEM reasonably believes that its estimation of formaldehyde emissions is appropriate and the source formaldehyde emissions are below 10 tons per year.

8. The applicant has agreed to install an oxidation catalyst, which will further control the formaldehyde emissions from the combustion turbines to much lower levels. This technology has been identified as one of the proposed Maximum Achievable Control Technology alternative available to the Permittee of combustion turbines to comply with upcoming federal regulation in this regard[1].

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[1] The regulation mentioned is the upcoming National Emissions Standard for Hazardous Air Pollutant for the combustion turbines to be proposed sometime in November 2002. Information available on the US EPA website at http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html.

Case 1: If a reactable concentration of mixed nitrogen oxides (“NOx”) are present and if reagent (ammonia, “NH3”) is present upon the catalyst and the temperature is below a critical point, then there will be no reaction and the reagent will be wasted (and the wasted reagent will itself then be emitted as an airborne pollutant).

Case 2: If a reactable concentration of NOx is present and if reagent is *not* present upon the catalyst and the temperature is at or above the “lowest effective” temperature,” (and no more than the highest effective temperature) then there will be no reaction and the NOx will be emitted as an airborne pollutant.

NOx BACT is required at all levels of operation, including SU/SD. The permit must be rewritten to obligate admission of reagent to the NOx selective catalytic reduction pollution control equipment (“PCE”) whenever there is a reactable concentration of NOx present and the catalyst is at an effective temperature. I.e. the permit is to prevent both case 1 and case 2.

Response 5:

The IDEM, OAQ’s intent behind the condition D.1.16 of the permit is to require the Permittee to operate NOx controls, when NOx is being emitted, and the exhaust temperature in the Selective Catalytic Reduction (SCR) is in the optimum temperature range for the catalyst. The catalyst in the SCR systems are heated only by the exhaust gases from the turbines and duct burners. Therefore, ensuring that the catalyst bed is hot enough also ensures that NOx is present in the exhaust gases because these gases originate at the turbine or the duct burners.

Further the SCR process is controlled by the CEMs which monitor the NOx emissions after the SCR in exhaust stack and feedback that information to the process control to ensure sufficient ammonia injection to reduce the NOx to nitrogen and water.

The condition D.1.16 (a) requires the Permittee to determine optimum temperature of the catalyst bed that demonstrates compliance with the NOx emissions limit in condition D.1.4. To further clarify this intent the condition D.1.16 is changed as follows:

D.1.16 Oxides of Nitrogen NOx (SCR operation) [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD requirements), the Permittee shall determine **the lowest** optimum temperature of the catalyst bed during the stack test ~~requirement~~ **required** in condition D.1.15 (a) **and** (d) that demonstrates compliance with limits in condition D.1.4, as approved by IDEM.

(b) From the date of the valid stack test, during a startup, the Permittee shall **measure and record temperature of the catalyst bed and** start ammonia injection in the SCR units to control NOx emissions from the gas turbines, as soon as the catalyst bed reaches the temperature determined in part (a) above or turbine load reaches 50%, whichever occurs earlier.

Comment 6:

Reagent emission limit
DEM and TIP agreed that BACT must be used to control NOx. Selective Catalytic Reduction

(“SCR”) PCE, wherein, in addition to an active catalyst at an effective temperature, a reagent is added, is to be applied with the goal of consuming NOx. The reagent is NH3, a poisonous gas designated in Appendix A to 40 CFR 355 as an “Extremely Hazardous Substance” (“EHS” as a result of it having been found to merit continued designation as such following initially being listed in 42 USC 7412(r)(3)); anhydrous, an aqueous solution, or an aqueous solution of urea; and it will be used by TGS in copious quantities. There appears nothing in the 12760 package as to where DEM computed or obtained the 12760 Condition D.1.11 limits, which are arbitrary and capricious. DEM correctly writes some of the harms of NH3 emission in the PM10 portion of Appendix C to the 12760 TSD and then writes nothing in re its derivation of a limit. DEM’s proposed 10 parts per million by volume NH3 on a dry basis adjusted to 15% molecular oxygen (“
excessive amount.

By the use of modern physical and electronic computational control devices, the emission of NH3 can be held to no more than 2 ppmvd as evidenced by Massachusetts permits. The USEPA Region 9 19 June 2001 letter from Rios to Dixon (“Rios” attached hereto and incorporated herein) says NOx BACT is presumed to be 2.0 ppmvd 1 hour average not the 12760 Condition D.1.4(a)(1) and (2) 2.5 ppmvd 3 hour average. Further, Rios suggests that 5 ppmvd NH3 is achievable for the 2 ppmvd NOx concentration. DEM, in PSD permits: Whiting Clean Energy, Lake County, 089- 11194- 00449 Condition D.1.8; Mirant, Vigo County, 167- 12208- 00123 Condition D.2.13; Cogentrix, Lawrence County, 093- 12432- 00021 Condition D.1.13; Duke, Vigo County, 167- 12481- 00125 Condition D.1.14; PSEG, Dearborn County, 029- 12517- 00033 Condition D.1.13; Acadia Bay, St. Joseph County, 141- 14198- 00543 Condition D.1.9; Cinergy, Hamilton County, 057- 12478- 00004 NH3 *unlimited*; and MVE, Posey County, draft 129- 12750- 00016 Condition D.1.10 (all for CT’s with SCR NOx PCE, and all incorporated herein by reference) has put forth a 10 ppmvd NH3 mantra with no technical basis whatsoever for why lower NH3 concentrations are not both achievable and reasonable in permit limits.

While Rios is in USEPA Region 9, the people of Region 5 have every bit as much of a right to the cleaner air that would come from the Rios CO, NOx, and NH3 lower emission rates and shorter averaging times. While NH3 is not mentioned in the federal PSD Regulation, 40 CFR 52.21 PM10 BACT requirement implicitly commands DEM to consider all that which contributes to PM10. Thus it is clear error that DEM has not evaluated *numerically* the harm of TGS emitting NH3. There is also an “environmental impact” criteria of BACT that implies human health, and DEM provided nothing in re if there was a ton less NH3 emitted, how much more NOx would be emitted and would that be more harmful to human health, together with a basis for DEM’s claim.

In the use of SCR NOx PCE, there are many attributes that can be adjusted to reduce NH3 emission; some of them are: 1) a greater catalyst area can be presented, 2) a more active catalyst can be presented, 3) the reactants can be caused to reside at the catalyst surface for a greater time, 4) the temperature can be better controlled to achieve greater reaction, and 5) the admission of NH3 equivalent reagent can be more carefully controlled to achieve less excess. It appears that DEM did nothing in re any of those methods.

Additionally, due to the EHS designation, as TGS is designed, what is the maximum possible accidental release of NH3? What is the annual expected throughput of NH3?

The 12760 Condition D.1.11(b) limit with Condition D.1.15(d) testing for compliance in no way qualifies as being federally enforceable. In accordance with the WM, DEM must require CEM of NH3 or proof of its infeasibility. A once every 5-year (or once) test cannot give any foundation to the limit.

Response 6:

In December 2001 and early 2002, IDEM, OAQ lowered the bar for NOx emission limit as BACT for the combustion turbines in the combined cycle mode. Before this, time the NOx emission limit for the combustion turbine in the combined cycle mode using SCR as control for NOx emissions, was set at 3 ppm @ 15% O2. This was at a time when the neighboring states in the Region 5 of the U.S. EPA was setting the NOx BACT for combined cycle combustion turbines at 3.5 – 5 ppm @ 15% O2. Permit decisions issued at that time in the States of California and Florida contain limitations of 2.5 ppm @ 15% O2 for NOx emissions as BACT determinations. Therefore, IDEM, OAQ lowered the NOx emission BACT level for the combined cycle combustion turbines to 2.5 ppm @ 15% O2. Even in recent BACT determinations, the neighboring states are still allowing up to 4.5 ppm of NOx emissions as BACT limit.

The IDEM, OAQ also lowered the CO emission limit as part of the BACT determination to no greater than 3.6 ppm @ 15% O2 in comparison to 8 ppm @ 15 % O2 currently proposed in Florida and other states around US (except plants in California and in north eastern states of US. A detailed discussion of this aspect is available in the Appendix C of the TSD).

The IDEM, OAQ has limited authority in terms of regulation of ammonia from this type of source. The following aspects were considered while evaluating the ammonia slip limitation in condition D.1.11 of the permit:

1. Ammonia (NH3) is not a criteria pollutant under the Clean Air Act.

2. NH3 is not a Hazardous Air Pollutant under Section 112 of the Clean Air Act.

3. NH3 is used to react with the NOx emissions present in the exhaust stream of the combustion turbines and duct burners in the Selective Catalytic Reduction systems to produce nitrogen and water.

4. The NH3 injection in the SCR system is controlled using a “feedback” system. The emission rate of NOx is monitored in the exhaust stream past the SCR system in the stack. The analyzer compares the NOx emission rate to the emission limit (which may be set lower than that allowed in the permit to prevent exceedence of permit limit by building a cushion) and sends a signal to the injection system to control the flow of ammonia to the SCR system. Ammonia is injected at the rate of 1:1 in proportion to the NOx emission rate at the inlet of the SCR. Based on this ratio, annual throughput of ammonia is expected to be about 5200 tons.

5. The ammonia used for ammonia injection in the SCR system is purchased from the commercial market and is not a freely available commodity for the Permittee. The level of NOx emission reduction is a function of the catalyst volume and ammonia to NOx ratio. Typically SCR catalyst manufacturers will guarantee a life of three years for low emission rate, high performance catalyst systems. Manufacturers typically estimate up to 20 ppm of un-reacted ammonia emissions when making NOx control guarantees at very low emission levels, however a properly operated SCR system will typically have small amounts of ammonia slip. In this permit, the NH3 slip is limited to 10 ppm @ 15% O2. To achieve low NOx limits, SCR vendors suggest a higher ammonia injection rate than what is stoichiometrically required, which results in ammonia slip. Ammonia slip can also occur when the exhaust temperature falls outside the optimum catalyst reaction, or when the catalyst becomes prematurely fouled or exceeds its life expectancy. For a given catalyst volume, higher NH3 to NOx ratios can be used to achieve higher NOx emission reduction rate. Therefore, even though the Permittee is required to maintain ammonia injection levels, to maintain NOx emission rates under BACT limits, it has incentive to minimize excess ammonia usage as much as possible.

6. As the CO emission levels in a combustion turbine are lowered (from the range of 9-10 ppm in 2000-2001 to the new lower level of 6 ppm in 2001 and 2002) it has the effect of raising the flame temperature in the combustor. This result in higher NOx emissions especially at colder ambient temperature where, the fuel input rate is high. The NOx vs. CO tradeoff is already explained in the appendix C of the TSD under the BACT

discussion. As the trade off for lowering the CO emission limit to 6 ppm, some "uncertainty" in terms of the uncontrolled NOx emissions exists. Due to this uncertainty a higher ammonia slip is possible to achieve the even lower NOx emission rate of 2.5 ppm.

The IDEM, OAQ likes to state for the record that the time the initial permit application was received in October of 2000, it contained the NOx BACT limit of 3.5 ppm and CO BACT limit of 10 ppm both at 15% O2. In subsequent discussions and evaluations of other related information and permitting standards, the IDEM, OAQ has lowered the BACT level for NOx to 2.5 ppm and that for CO to 6.0 ppm both at 15% O2.

7. Ammonia is not a criteria pollutant and is not subject to the requirements of 326 IAC 2-2-3 (Control Technology Review) and therefore, emissions are not subject to case-by-case, top down, Best Available Control Technology determinations. The Rios letter[1] cited by the commentator states "We also expect that 5 ppmvd ammonia slip can be achieved at the 2.0 ppmvd NOx level." The letter never mentions this limit as a BACT standard. Further it has to be kept in mind that the project in consideration in this letter is located in State of California where weather conditions are not as harsh as they are for the plants located in Indiana. It is common industry knowledge that colder temperature can cause large increases in the NOx and CO emissions from the combustion turbines. As the dry low NOx combustors on these turbines will be always tuned to minimize CO emissions, the fluctuations in the NOx emissions will have to be controlled using the SCR system. Therefore, providing the cushion to the Permittee in the ammonia slip limit ensures that the NOx emissions are controlled consistently and continuously below the BACT limit in the permit.

8. In an order denying review[2], the Environmental Appeals Board stated that "With regard to the ammonia emission limits on which Rebound believes it and others should have the chance to comment, ammonia emission limits are only regulated under federal PSD regulations in the BACT context.** With this as our predicate, and since we have found that the permitting authorities did not commit clear error in not updating the BACT determination for NOx , public comment on the ammonia limit is not required under the federal PSD regulations." The item ** in this opinion is a footnote stated as "**Ammonia slip emissions must be reviewed for their collateral effects when evaluating certain control technologies during a BACT analysis. SCR, which uses ammonia as a catalyst to reduce NOx emissions, is such a technology that requires the collateral effects of ammonia slip to be evaluated. *See In re Three Mountain Power,* PSD Appeal No. 01-05, slip op. at 25 n.18 (EAB, May 30, 2001), 10 E.A.D.__."

9. In another order denying review[3], the Environmental Appeals Board stated that "… and TMP can achieve the appropriate BACT limits using either SCONOx or SCR. Moreover, as we will discuss …. Collateral impacts, such as ammonia slip, do not compel the rejection of SCR in this case. For this reason, we conclude that the District's selection of

In this regard, the NSR workshop manual by US EPA[4] stated that, "After the identification of available and technically feasible control technology options, the energy,

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[1] Letter from Gerardo Rios, Acting Chief, Air Permits Office, U.S. EPA Region IX to David White of San Luis Obispo Air Pollution Control District dated June 19, 2001

[2] See "In re: Chehalis Generating Facility, Permit No. EFSEC/95-02", PSD Appeal No.01-06, Before the Environmental Appeals Board of U.S.EPA., August 20, 2001.

[3] See "In re: Chehalis Generating Facility, Permit No. EFSEC/95-02", PSD Appeal No.01-06, Before the Environmental Appeals Board of U.S.EPA., August 20, 2001.

[4] See Chapter B, "Best Available Control Technology", in the , "New Source Review Workshop Manual", by US EPA, Draft – October 1990.

environmental, and economic impacts are considered to arrive at the final level of control. At this point the analysis presents the associated impacts of the control option in the listing. For each option the applicant is responsible for presenting an objective evaluation of each impact. Both beneficial and adverse impacts should be discussed and, where possible, quantified. In general, the BACT analysis should focus on the direct impact of the control alternative.

If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider *whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option*. If there are no outstanding issues *regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT*. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT." [emphasis added]

Further the NSR manual by US EPA[1] stated that, "In limited other instances, though, control of regulated pollutant emissions may compete with control of toxic compounds, as in the case of certain selective catalytic reduction (SCR) NOx control technologies. The SCR technology itself results in emissions of ammonia, which increase, generally speaking, with increasing levels of NOx control. It is the intent of the toxics screening in the BACT procedure to identify and quantify this type of toxic effect. Generally, toxic effects of this type will not necessarily be overriding concerns and will likely not to affect BACT decisions. Rather, the intent is to require a screening of toxics emissions effects to ensure that a possible overriding toxics issue does not escape notice."

In this case, the Appendix C of the TSD "Best Available Control Technology" contains the detailed discussion with regard to selection of control for NOx emissions. The IDEM, OAQ evaluated the various control technologies and considered the impacts of collateral emissions of ammonia slip from the SCR. The IDEM, OAQ has quantified the emissions of ammonia from the SCR system and shown that the use of SCR as a control for NOx emissions is justified for this plant.

10. The Permittee shall install a Continuous Emission Monitoring System for NOx emissions, which shall meet the regulatory requirements and shall be used to control ammonia injection flow based on the NOx concentration in the exhaust gases. The ammonia flow will vary in accordance with increase or decrease in NOx concentration in the exhaust gases. The ammonia CEMs are not common at this time and IDEM, OAQ is not aware of any Sources in Region 5 States of US EPA using CEMs to show compliance with ammonia slip limitation. The installation of ammonia CEMs will be an unnecessary economic burden on the Source and does not yield any significant environmental benefits.

It is expected that the Permittee shall operate the SCR system in accordance with the requirements of the permit and practices recommended by the manufacturer. The continuous emission monitoring system for the NOx emissions will provide accurate information to establish if the Permittee has been complying with the applicable limits. The Permittee may rely on the parameters listed by the commentator and any other parameters, to operate the SCR to best of its ability and performance level to achieve desired NOx emissions reductions.

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[1] See Chapter B, "Best Available Control Technology", in the , "New Source Review Workshop Manual", by US EPA, Draft – October 1990.

11. Indiana is one of the few states, which specifies any limitation for the collateral ammonia emissions from the use of SCR in the permit. This is to prevent the excessive use of ammonia to meet the NOx limit when the catalyst has degraded.

Therefore, based on above discussion, IDEM, OAQ will keep the NH3 slip limit for this Source unchanged. No changes are made to any permit conditions.

Comment 7:

Proof of performance
In accordance with the WM p. H.10 Table H.2 point 9 text: "Performance tests should determine *both emissions and control equipment efficiency*" (emphasis in original). It appears that DEM has made no mention of the NOx PCE efficiency in the 12760 permit draft. Clearly the test regimen must be expanded to include NOx PCE efficiency.

Response 7:

The SCR control efficiency in the Appendix C of the TSD was used to establish the NOx emission rate in ppm @ 15% O2, post add-on control, from the combustion turbine. The emission rate corresponding to a minimum level of control efficiency of SCR has been included in the permit. The Permittee shall meet this emission rate to show compliance with the BACT level of control for NOx emissions. Therefore, adding control efficiency percentage limitation in the permit will be redundant and burdensome to show compliance with. No changes are made to any permit conditions.

Comment 8:

CO BACT
The 12760 Condition D.1.5(a)(1) and (2) limits of 27.8 and 52.8 pounds CO / hr translate roughly into 27.8 / 2.112 = 13.16 and 52.8 / (2.112 + 0.550) = 19.83 pounds CO per BBTU respectively. 12760 Condition D.1.5(a)(2) is a dilution, a cheapening of BACT, for it is an average of the 13.16 pound CO / BBTU rate on the 2.112 BBTU turbine with a whopping (52.8 - 27.8) / 0.550 = 45.45 pound CO / BBTU rate on the 0.550 BBTU duct burner. BACT is to apply to all levels of production. BACT is to apply on Day 1. 12760 Conditions D.1.5(a)(2) and (7) must be struck. 12760 Condition D.1.5(a)(1) must be edited so as to apply to the total of the turbine and duct burner, and, in accordance with Rios, be reduced to 2.0 ppmvd CO averaged over no more than 3 hours and mass rate of 4.39 pounds CO per BBTU for any combination of turbine and duct burner firing. There is little doubt that with the desire of TIP to use duct burners, TIP is obligated to have properly sized and properly thermally placed oxidation catalyst PCE as CO BACT installed for operation on Day 1. With the oxidation catalyst, the test regimen must be expanded to include CO PCE efficiency.

Response 8:

The primary emissions limit used to establish and compare Best Available Control Technology (BACT) determination is parts per million (ppm). The use of pounds per hour (lb/hour) emission rate for comparison of BACT limits are misleading because they are dependent upon the throughput or maximum capacity of the equipment. This is especially true in case of combustion turbines where one observes a large variation in the emission rates due to variations in the ambient temperature and load on the combustion turbine. The emissions data submitted by the applicant show these variations in ppm @ 15% O2 and lb/hour for the Mitsubishi 501 F combustion turbines in combined cycle mode using duct burner for supplemental firing. This data shows that the CO emissions from the combustion turbine and duct burner combined at 0^{o}F are 9.0 ppm @ 15% O2 and is equivalent to 52.8 lb/hour. Depending upon the ambient temperature the air flow and combustion characteristics in the combustion turbine and the duct burners are affected. Even though duct burners are placed in the turbine exhaust where excess oxygen concentration is high, the ambient temperature can influence the flame temperature causing the formation of high CO emissions.

In case of permit analysis and the development of the Technical Support Document, IDEM, OAQ uses three different type of emission measurement units. The tons per year emission rate are used to establish the status (PSD major or minor) of the project. The pounds per hour emission rates further consist of two types. The first is the pound per hour emission rates at 59^{o}F which is used to calculate the tons per year and also to evaluate the BACT control technologies cost effectiveness in terms of dollars per ton of pollutant removed. This is based on 59^{o}F as the average scenario, which takes into account the high emission rates during the cold temperature month and low emission rates during the hot months. The second type of pounds per hour emission rate is based on worst case emissions at cold ambient temperature (0^{o}F). This emission rate is actually biased against the Permittee and is used to evaluate the impacts on ambient air quality from the operation of this new source. So the higher value of this pounds per hour when used in a model shows the worst case impact on the ambient air quality. This pounds per hour emission rate is also stated in the permit as an emission rate in addition to the ppm @ 15% O2 limit. This pounds per hour emission limit is added because it protects the National Ambient Air Quality Standard and in no case to be exceeded by the Permittee. The actual BACT emission limit in the permit for NOx and CO emissions is in the form of ppm @ 15% O2. Therefore, the commentator's assumptions of pound per hour emission rate as inappropriate BACT are not relevant. As shown in the TSD appendix C, the BACT for CO emission limit is comparable to other similar sources permitted in recent months in the United States.

Therefore, no changes are made to any permit conditions.

Comment 9:

<u>Power augmentation BACT</u>
DEM placed nothing in the record showing that it did anything other than set 12760 Condition D.1.5(a)(3) in an arbitrary and capricious manner (I.e. DEM did no BACT analysis for this phase of operation whatsoever). Obviously such high CO levels call for an oxidation catalyst as BACT PCE.

Response 9:

The IDEM, OAQ had investigated other permits for power augmentation mode and observed that emissions during power augmentation are higher than during the operation without power augmentation. The IDEM, OAQ took into account the high CO emission rate during the power augmentation mode while evaluating the add-on control technologies for controlling CO emissions. Based on U.S.EPA Region 5 email comments for this permit received on July 30, 2002 the CO BACT is reevaluated and is presented in the following pages.

Comment 10:

<u>SU/SD BACT</u>
DEM placed nothing in the record showing that it did anything other than set 12760 Condition D.1.12(d) in an arbitrary and capricious manner (I.e. DEM did no BACT analysis for this phase of operation whatsoever). Obviously such high CO levels call for an oxidation catalyst as BACT PCE. And, as the catalyst is cold and ineffective during the SU phase, electric heaters must be required to be used prior to the generation of CO (ignition) of the turbine. Several megawatthours of electricity would likely serve to abate several tons of CO, and at a 1:1 ratio, the economic value of doing such is sound.

Response 10:

IDEM, OAQ researched the BACT determinations and the manufacturer's specifications for various other projects. Limited information was available for BACT limits in other similar permits for startup and shutdown of turbines. Therefore, IDEM, OAQ relied on manufacturer recommended startup practice and emission estimate to establish the BACT levels.

Also, the commentator is suggesting that the Permittee should add electrical heaters to heat the exhaust space of the turbine before the turbine is even fired up. The temperature to which it should be raised will be in the range of 800-1000 ^{o}F, so that any gases, which pass through this space, are heated to that temperature and then are subsequently reduced in the CO oxidation catalyst zone as the temperature will be in the optimum range. IDEM, OAQ believes this would not be an environmentally sound option. The commentator is suggesting to decrease a few tons of CO emissions during the startup of the turbine that the Permittee should use many megawatts of electric power generated using existing coal fired boilers located in Indiana or somewhere else in the United States. This electric supply will be carried over long distances and with transmission losses will further increase the demand for the electricity on the coal fire boilers. These boilers will generate many tons of PM10, NOx, CO and Mercury emissions to supply this power to control few tons of CO emissions. In IDEM, OAQ's view it will harm the environment significantly to generate additional tons of PM10, NOx, CO and mercury emissions from the boiler to control few tons of CO emissions from these turbines. The IDEM, OAQ is not aware of any other plants where this preheating of exhaust gases is practiced or proposed. Therefore, no changes are made to any permit conditions.

Written comments were received from Region 5 office of U.S.EPA, on July 30, 2002. These comments and IDEM, OAQ responses, including changes to the permit (where language deleted is shown with strikeout and that added is shown in bold) are as follows:

Comment 1:

A proper BACT economic feasibility analysis of CO Catalytic Oxidizer must account for tons of reductions of both VOCs and CO emissions. Therefore, in this permit, the economic feasibility of CO oxidation catalyst should be checked with respect to CO and VOC emissions.

Response 1:

The IDEM, OAQ has revised the emission calculations for this project. The change was required because the high CO emission rate during the power augmentation mode was erroneously left out of the calculations. These calculations are attached to this document as Appendix A to the TSD addendum. The two tables showing the emissions before and after control and limitations as shown in the TSD are revised and are shown below:

Potential to Emit of Source before Controls and Enforceable limits

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as "the maximum capacity of a stationary source or emissions unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, the department, or the appropriate local air pollution control agency".

Pollutant	Potential To Emit (tons/year)
PM	644.9
PM-10	644.9
SO_2	516.0
VOC	575.1
CO	**7001.4** ~~5914.2~~
NO_x	7947.6

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM, PM-10, SO_2, VOC and NOx are greater than 25 tons per year and of CO is greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-5.1-3.

(b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM, PM-10, SO_2, VOC, CO and NOx is greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

(c) Fugitive Emissions
Since this type of operation is one of the twenty-eight (28) listed source categories under 326 IAC 2-2, the fugitive emissions are counted toward determination of PSD applicability.

Source Status

New Source PSD Definition (emissions after controls, based on 8,760 hours of operation per year at rated capacity and/ or as otherwise limited):

Pollutant	Emissions (ton/yr)	Significance Threshold Levels (tons/year)
PM	481.6	25
PM10	481.6	15
SO_2	356.4	40
H_2SO_4 Mist	212.9	7
VOC	389.0	40
CO	**5092.5** ~~5409.3~~	100
NO_x	961.1	40

(a) This Source is major for PM, PM_{10}, VOC, CO, SO_2, H_2SO_4, and NOx emissions.

(b) The NO_X emissions from the combustion turbine and duct burner shall be controlled by a dry low NOx combustion system for the gas turbine, low NOx duct burners and selective catalytic reduction (SCR) system.

(c) The CO emissions from the combustion turbine and duct burner shall be controlled by using dry low NO_x combustion system and good combustion practices. A catalytic oxidation system will be installed if the emission limitations established for the turbine and duct burner can not be achieved with the dry low NO_x combustion system and good combustion practices.

(d) The combined-cycle power plant is a major stationary source because at least one regulated pollutant is emitted above its associated major source threshold level. Also the proposed facility is classified as a “fossil fuel-fired steam electric plant of more than 250 MMBtu per hour” and is therefore one of the 28 listed categories, as stated in 326 IAC 2-2.

The applicant has agreed to install and operate oxidation catalyst to control CO and VOC emissions from the combined cycle combustion turbines. This control technology was the topmost technology identified in the BACT analysis in the Appendix C of the TSD on pages 11 and 18 of 28. Therefore, in accordance with NSR manual[1] as the applicant has selected the top control technology in the BACT analysis, and there are no impacts of unregulated air pollutants or impacts on other media, the economic feasibility of this technology is not considered relevant in

[1] See page B.8, Chapter B, “Best Available Control Technology”, in the , “New Source Review Workshop Manual”, by US EPA, Draft

this analysis and not included in the further discussions.

Comment 2:

See TSD Appendix A: Table "Emissions Calculations from Combined Cycle (strikethrough: Opeartion) Operations" In the table when calculating Shutdown Emission Rate per turbine (lb/shutdown), (70) x (0.67) = 46.9 NOT "49.6". This should be corrected in the final permit.

Response 2:

It is a matter of coincidence that the two numbers 46.9 and 49.6 look as if they are similar. This calculation is incorrect because by multiplying 70 (which is the number of shutdowns in each category of hot/warm/cold startups in one year) and 0.67 (which is the duration in hours it takes to shutdown a turbine) one does not arrive at lb/shutdown as shown below:

$$70\ \frac{\text{No. of Shutdown}}{\text{year}} \times 0.67\ \frac{\text{hour}}{\text{1 Shutdown}} = 46.9\ \frac{\text{hours in shutdown mode in each category of startup}}{\text{year}}$$

Whereas, the number 49.6 is the pounds of emission per startup. Therefore, the two numbers are completely independent of each other and their matching is purely coincidental.

Therefore, no change is required to any permit conditions.

Comment 3:

See TSD page 10: In the table, under "Combustion Turbines and Duct Burners": "Good Combustion Control..." Should be changed to "Good Combustion Design..."

Response 3:

The IDEM, OAQ likes to acknowledge this change with respect to the VOC emissions mentioned in the table on page 10 of the TSD. The TSD for the draft permit is not modified as it reflects the background information for the draft permit. All changes in the TSD are documented in the addendum to the TSD.

Written comments were received from the members of Citizens for Positive Industry of Petersburg, Indiana, on July 30, 2002. For the record, 16 individuals signed the letter and the original letter will be added to the public file for this Source at IDEM. Additional written comments were received the same day from Jodi L. Jochin and Ellex C. Taylor of Petersburg, Indiana separately. The summary of the comments and IDEM, OAQ responses, including changes to the permit (where language deleted is shown with strikeout and that added is shown in bold) are as follows:

Comment from Citizen for Positive Industry:

The letter stated that the IDEM has listed Pike County in the top 10 worst polluted counties for the past 3 years. There are two coal power plants causing pollution problem in the Pike County. IDEM has issued Ozone alerts for southern Indiana 4 days this summer. Pike County does not have any monitoring system for NOx concentrations in the ambient air. The citizens have requested that a system be placed for a duration of 1 year to monitor the current levels and IDEM has not responded to these requests. IDEM’s role in the permitting process is rubber stamping the approval of the application and hiding behind the fact that the Indiana and EPA laws does not protect the citizens. IDEM’s role should be lobbying to change the laws to help protect Indiana but in reality IDEM protects the polluters. Tonight IDEM will hear from misfortunate uninformed people about jobs and taxes. Issues that have nothing to do with the approval of the permits sought by Tenaska. It is moral injustice to the citizens of Pike County to have no say in what they are asked to breath and drink.

Comment from Jodi L. Jochin:

The commentator expressed concern about the general state of affairs. The letter expressed general concern for the pollution in the State or County. The commentator expressed a need for right kind of regulation that says “no” to the pollution.

Comment from Ellex C. Taylor:

The letter raised the objection that Tenaska plant should only be allowed to build if they can guarantee zero emissions. The commentator’s stated that the two existing coal fired power plants in the County are polluting the area to one of the highest polluted County in the State. The added pollution would affect the air, water supply, crops, live stock and the climate change.

The commentator requested that the permit not to be granted to the Tenaska Indiana Partners L.P.

Response:

The IDEM, OAQ works to safeguard the quality of Indiana’s air through implementing the requirements of the Clean Air Act, developing state rules governing air quality standards, evaluating and issuing permits for construction and operation and monitoring Indiana’s air quality. These programs continue to reduce the levels of air pollution across the state every year. The OAQ routinely performs air quality analysis to insure that issuance of a permit will not result in a violation of any state or federal air regulations and standards. A permit would be denied if the application does not meet the requirement of 326 IAC2-2 (Prevention of Significant Deterioration) or if the source would pose a threat to public health. In addition, the air quality analysis conducted demonstrates that air quality in the vicinity of the plant will continue to comply with the air quality standards. No significant impact on public health or welfare is expected to occur as a result of the emissions from the proposed facility.

If the applicant complies with all state and federal requirements and the air quality analysis demonstrates that the source will not have significant impact on the environment and human health, then the IDEM is obligated by law to issue the permit. If significant sources are located nearby, then the OAQ takes that into account when performing the air quality demonstration.

Also, natural gas is one of the cleanest burning fuels that can be used for combustion. Coal on the other hand is one of the dirtiest fuels that can be combusted. In general coal emissions for some pollutants can be several times larger than a similar sized natural gas fired plant. The following table compares the emissions (after controls) from the gas fired plant with those from a fluidized bed coal fired plant with an even lesser capacity. This particular boiler is a circulating fluidized bed boiler designed to minimize SO2 emissions as compared to a conventional utility coal fired boiler.

Pollutant	820 MW Natural gas fired plant (tons/year)	Fluidized bed 500 MW coal fired plant (tons/year)
PM	332.14	350
Sox	174.81	5000
VOC	100.94	300
CO	1454.70	5800
NOx	439.38	2700

Based on the results of the air quality modeling analysis, IDEM does not believe that the emissions from Tenaska plant can cause or contribute to a significant impact on public health. This permit includes many monitoring and testing requirements to ensure that emissions are in continuous compliance with air quality rules. This permit requires the source to monitor the control device and install continuous emission monitoring systems to show compliance with the BACT limits for NOx and CO emissions. If an abnormal situation is observed, the permit requires the source to take corrective actions to fix the problem. The permit also requires stack testing to verify compliance with the applicable limits.

The construction permit rules require that a permit be issued if the applicant is required to comply with permit conditions detailing the requirements of the air pollution control rules and any other conditions necessary to protect public health. The EPA and the Indiana Air Pollution Control Board approve the laws that govern air quality in Indiana. IDEM is delegated to enforce those laws as they currently exist, but does not have the sole authority to change them.

If citizens wish to participate in the process for creating new laws or amending existing laws that govern air pollution, they can participate in the Air Pollution Control Board meetings. There are two ways for a person to receive a copy of the agenda for upcoming board meetings. The first option is an email notification that's sent out two weeks before the board meeting. A notification goes out to those on the list that the board materials are available on line for viewing/downloading. http://www.IN.gov/idem/air/rules/airboard/. The second option is for people that wish to get the agenda by mail. The mailing also includes the web address to view the board documents on line. Anyone can email Karol Chuma to request to be added to the email notification at kchuma@dem.state.in.us or call 317-233-0426 and to be added to the agenda mailing list.

The IDEM, OAQ would also like to highlight that the permitting process is not just rubber stamping the application received from the applicant as approved. As can be seen in this case, it is a long process of investigation and analysis to make sure that all federal and state regulatory requirements are complied with. As can be seen in this permit, the original application contained 3.5 ppm for NOx and 10 ppm for CO as proposed BACT limit. Over the period of two years and rigorous research and discussions, the applicant has agreed with the IDEM, OAQ's recommendations to reduce these BACT limits to 2.5 ppm for NOx and 3.6 ppm for CO. The safeguard of quality of environment and compliance with applicable regulations are the primary concerns for IDEM, OAQ during the permitting process. The applicant has agreed to install oxidation catalyst to control CO and VOC emissions and sets a unique precedence of this type of control for the projects located in attainment area for CO and VOC emissions.

If a source is located in an area designated as nonattainment with the National Ambient Air Quality Standards, then the source will need to comply with more stringent requirements. However, Pike County is considered attainment for all criteria pollutants. For attainment areas, the air pollution laws don't require a freeze on new major source construction unless reductions are created at the existing sources in the area as required in the non-attainment areas.

No changes are made to any permit conditions.

On July 30, 2002, Berger and Berger Attorneys and Counselors at Law submitted detailed written comments on this permit during the public comment period on behalf of the Southwest Indiana Building and Construction Trades Council and all of its members and the affiliated local unions. In a subsequent letter dated September 11, 2002, Berger and Berger on behalf of the Southwestern Indiana Building and Construction Trade Councils and affiliated unions withdrew the comments made earlier on the permit. Therefore, no review was carried out of these comments.

The public hearing for this permit was conducted on July 30, 2002 at the Petersburg Elementary School, Petersburg, Indiana. All the speakers at this hearing spoke in favor of the project. The transcript of this hearing has been added to the public files as part of the record for this Source available in the file room of the IDEM.

Further IDEM, OAQ has made changes to permit conditions to clarify the intent. These changes are as follows (where language deleted is shown with strikeout and that added is shown in bold):

1. Condition B.3 is changed as follows:

B.3 Effective Date of the Permit [IC13-15-5-3]

Pursuant to 40 CFR 124.15, 40 CFR 124.19, and 40 CFR 124.20, the effective date of this permit will be thirty (30) days after the service of notice of the decision, ~~if~~ **since** comments are received during the public comment period for this permit. Three (3) days shall be added to the thirty (30) day period if service of notice is by mail.

2. Condition C.4 is changed to make it consistent with the rule as follows:

C.4 Inspection and Entry [326 IAC 2-5.1-3(e)(4)(B)] [326 IAC 2-6.1-5(a)(4)]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a permitted source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

(b) Have access to and copy~~, at reasonable times,~~ any records that must be kept under this title or the conditions of this permit or any operating permit revisions;

(c) Inspect~~, at reasonable times,~~ any processes, emissions units (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit or any operating permit revisions;

(d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) Utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

3. The condition C.13 is revised to make it consistent with the rule as follows:

~~C.13 Maintenance of Monitoring Equipment [IC 13-14-1-13]~~

~~(a) In the event that a breakdown of the monitoring equipment occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem. To the extent practicable, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less frequent than required in Section D of this permit until such time as the monitoring equipment is back in operation. In the case of continuous monitoring, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less than one (1) hour until such time as the continuous monitor is back in operation.~~

~~(b) The Permittee shall install, calibrate, quality assure, maintain, and operate all necessary monitors and related equipment. In addition, prompt corrective action shall be initiated whenever indicated.~~

C.13 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-6-5(3)(A)(iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment. In addition, prompt corrective action shall be initiated whenever indicated.

(b) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(c) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or will be down for calibration, maintenance, or repairs for a period of four (4) hours or more, supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.

(d) Nothing in this condition, or in Section D of this permit, shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5-1 (d)(1), 40 CFR 72 (Acid Rain Permit) and 40 CFR 60, Subpart GG (Stationary Gas Turbines).

4. Condition D.1.1 is changed as follows to clarify that the emission limits apply to both PM and PM10 emissions:

D.1.1 Particulate Matter (PM/PM_{10}) Emission Limitations for Combustion Turbines/Duct Burners [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), the PM (filterable) emissions ~~or PM_{10} (filterable and condensible) emissions~~ from each combustion turbine shall not exceed 0.005 pounds per MMBtu (higher heating value basis) and shall not exceed 9.0 pounds per hour.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the PM_{10} (filterable and condensible) emissions from each combustion turbine shall not exceed 0.005 pounds per MMBtu (higher heating value basis) and shall not exceed 9.0 pounds per hour.

(~~b~~**c)** Pursuant to 326 IAC 2-2 (PSD Requirements), the PM (filterable) ~~or PM_{10} (filterable and condensible)~~ emissions from each combustion turbine when its associated duct burner is operating, shall not exceed 0.0075 lb/MMBtu (higher heating value basis) and shall not exceed 19.4 pounds per hour.

(d) Pursuant to 326 IAC 2-2 (PSD Requirements), the PM_{10} (filterable and condensible) emissions from each combustion turbine when its associated duct burner is operating, shall not exceed 0.0075 lb/MMBtu (higher heating value basis) and shall not exceed 19.4 pounds per hour.

5. The condition D.1.2 is modified to clarify that the opacity limitation applies at all times:

D.1.2 Opacity Limitations [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the opacity from each combustion turbine stack shall not exceed twenty (20) percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent. ~~The opacity standards apply at all times, except during periods of startup, shutdown or malfunction.~~

6. The indentation in the condition D.1.4 is modified to show that only separate BACT emission limitations are applicable to the NOx emissions during the startup and shutdown modes. All other items in the list apply at all times the combustion turbines are operating:

D.1.4 Nitrogen Oxides (NO_X) Emission Limitations for Combustion Turbines/Duct Burners [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD Requirements) each combustion turbine/steam generating unit shall comply with the following, excluding startup and shutdown periods:

(1) During normal combined-cycle operation (fifty (50) percent load or more), the

NO_X emissions from each combustion turbine stack shall not exceed 2.5 ppmvd corrected to fifteen (15) percent oxygen, average on a three (3) operating hour period and shall not exceed 19.1 pounds per hour.

(2) During normal combined cycle operation (fifty (50) percent load or more), the NO_X emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 2.5 ppmvd corrected to fifteen (15) percent oxygen, averaged on a three (3) operating hour period, and shall not exceed 24.1 pounds per hour.

(b)~~(3)~~ The duct burners shall not be operated until normal combined cycle operation begins.

(c)~~(4)~~ Each combustion turbine shall be equipped with dry low-NO_X combustors and operated using good combustion practices to control NO_X emissions.

(d)~~(5)~~ A selective catalytic reduction (SCR) system shall be installed and operated at all times to control NOx emissions when the combustion turbines are operating, except during periods of startup and shutdown.

(e)~~(6)~~ Use natural gas as the only fuel.

(f)~~(b)~~ Pursuant to 326 IAC 2-2 (PSD Requirements), the annual NO_X emission from each combustion turbine and associated duct burner, excluding startup and shutdown emissions, shall not exceed 87 tons per year.

7. Condition D.1.9 is changed as follows to make it consistent with the present model condition:

D.1.9 40 CFR Part 60, Subpart Da (Electric Utility Steam Generating Units)

The heat recovery steam generator (HRSG) duct burners (DB) are subject to 40 CFR Part 60, Subpart Da because the heat input capacity is greater than 250 MMBtu/hr on a higher heating value basis.

Pursuant to 40 CFR Part 60, Subpart Da,

(a) The opacity from each combustion turbine stack, when its associated duct burner is operating, shall not exceed twenty (20) percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction. This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

(b) The PM emissions from each duct burner shall not exceed 0.03 pounds per MMBtu heat input on a higher heating value basis. ~~Compliance with Condition D.2.2 constitutes compliance with this condition.~~

8. Condition D.1.11 is modified as follows to clarify the intent of ammonia slip limit:

D.1.11 Ammonia Limitations [326 IAC 2-1.1-5] **[326 IAC 2-2]**

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements) **and 324 IAC 2-2**, **to maintain the optimum performance of the SCR,** the ammonia emissions from each combined cycle combustion turbine stack:

(a) shall not exceed ten (10) ppmvd corrected to 15% O_2 on 3 hour block average basis, and

(b) shall not exceed 140 tons per calendar year.

9. Condition D.1.13 is changed as follows to limit the percentage of drift losses allowed from the cooling towers:

D.1.13 Cooling Tower Particulate Matter Emissions (PM/PM_{10}) [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) each cooling tower shall comply with the following:

(a) **The drift losses from the cooling tower shall not exceed 0.0005% of cooling water,**

(~~a~~**b**) PM emissions shall be less than 1.1 pounds per hour, and

(~~b~~**c**) Employ good design and operation practices to limit emissions from the cooling towers.

10. Condition D.1.15 is changed as follows to make it consistent with the model and NSPS requirements:

D.1.15 Performance Testing

(a) Pursuant to 326 IAC 3-5 the Permittee shall conduct a performance test, **within 60 days of achieving maximum production but** no later than one-hundred and eighty days (180) after the facility startup or monitor installation, on the combustion turbine exhaust stack in order to certify the continuous emission monitoring systems for NO_X and CO.

(b) Within **60 days of achieving maximum production but no later than** one hundred and eighty (180) days after initial startup, the Permittee shall perform a formaldehyde stack test for each combustion turbine stack utilizing a method approved by the commissioner when operating at 50%, 75% and 100% load and power augmentation mode. These tests shall be performed in accordance with Section C – Performance Testing, in order to ~~verify~~ **demonstrate compliance with** the formaldehyde emission ~~factor~~ **limit** specified in condition D.1.10.

(c) Within sixty (60) days of achieving maximum production rate, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall conduct NO_X and SO_2 stack tests for each combustion turbine stack utilizing methods approved by the Commissioner. The Permittee can use alternative methods to determine compliance as specified in 40 CFR 60 Subpart GG. These tests shall be performed in accordance with 40 CFR 60.335 and Section C – Performance Testing, in order to document compliance with Condition D.1.4, ~~and~~ D.1.6 (1) **and D.1.8**. **In addition the Permittee shall utilize compliance provisions specified in 40 CFR 60 Subpart Da under 40 CFR 60.46a to show compliance with the NOx emissions limit in condition D.1.9 for the operation of duct burners.**

(d) Within **sixty (60) days of achieving maximum production rate, but no later than** one-hundred and eighty (180) days after initial startup, the Permittee shall perform $PM_{\cancel{10}}$ ~~(filterable and condensible)~~, VOC, H_2SO_4 mist and ammonia stack tests for each combustion turbine stack utilizing methods approved by the Commissioner. These tests shall be performed in accordance with 40 CFR 60.335, 40 CFR 60.48(a), and Section C – Performance Testing, in order to document compliance with D.1.1(a) and (b), **D.1.9,** D.1.7, D.1.6 (2) and D.1.11.

(e) IDEM, OAQ retain**s** the authority under 326 IAC 2-1.1-8(f) to require the Permittee to perform additional and future compliance testing as necessary.

11. Condition D.1.18 is changed as follows:

D.1.18 Continuous Emission Monitoring (CEMs) **[40 CFR 60 Subpart GG] [40 CFR 75] [326 IAC 3-5]**

(a) The owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 326 IAC 2-2, shall be required to install a continuous emissions monitoring system~~ or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5-1(d)~~.

(b) The Permittee shall install, calibrate, certify, operate and maintain a continuous emission monitoring system for NO_X and CO for stacks designated as 1 through 6 in accordance with 326 IAC 3-5-2 through 326 IAC 3-5-7.

(1) The continuous emission monitoring system**s** (CEMS) shall measure NO_X and CO emissions rates in pounds per hour and parts per million (ppmvd) corrected to 15% O_2. The use of CEMS to measure and record the NO_X and CO ~~hourly~~ **ppmvd** limits, is sufficient to demonstrate compliance with the limitations established in the BACT analysis and set forth in the permit. To demonstrate compliance with the NO_X limits, the source shall take an average of the parts per million (ppm) corrected to 15% O_2 over a three (3) operating hour period. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) corrected to 15% O_2 over a twenty four (24) operating hour period. The source shall maintain records of the **emissions** parts per million and the pounds per hour.

(2) The Permittee shall determine compliance with Conditions D.1.4 and D.1.5 utilizing data from the NO_X, CO, and O_2 CEMS, the fuel flow meter, and Method 19 calculations.

(3) The Permittee shall submit to IDEM, OAQ, within ninety (90) days after monitor installation, a complete written Monitoring Plan, in accordance with the requirements of 40 CFR Part 75.

(4) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.

(c) Pursuant to 40 CFR 60.47(d), the Permittee shall install, calibrate, certify and operate continuous emissions monitors for carbon dioxide or oxygen at each location where nitrogen oxide emissions are monitored.

12. Condition D.1.19 is changed as follows:

D.1.19 Record Keeping Requirements **[326 IAC 2-6.1-5 (a) (2)]**

(a) To document compliance with Conditions D.1.1, and D.1.4 through D.1.7, the Permittee shall maintain records of the following:

(1) Amount of natural gas combusted (in MMCF) per turbine during each month.

(2) Percent sulfur of the natural gas.

(3) Heat input on a lower heating value basis of each turbine on a 30-day rolling average.

(b) To document compliance with Conditions D.1.4, D.1.5 and D.1.12, the Permittee shall maintain records of the following:

(1) The type of operation (i.e. startup or shutdown) with supporting operational data.

(2) The duration of all startup and shutdown events **and total hours of startup and shutdown**.

(3) The CEMS data, fuel flow meter data, and Method 19 calculations corresponding to each startup and shutdown period.

(c) To document compliance with Conditions D.1.4 and D.1.5, the Permittee shall maintain records of the emission rates of NO_X and CO in pounds per hour and parts per million (ppmvd) corrected to 15% oxygen.

(d) To document compliance with Condition D.1.17, the Permittee shall maintain records, including raw data of all monitoring data and supporting information, for a minimum of five (5) years from the date described in 326 IAC 3-5-7(a). The records shall include the information described in 326 IAC 3-5-7(b).

(e) To document compliance with Condition D.1.8, the Permittee shall maintain records of the natural gas analyses, including the sulfur and nitrogen content of the gas, for a period of three (3) years.

(f) All records shall be maintained in accordance with Section C – General Record Keeping Requirements, of this permit.

12. The rule cite is added to condition D.1.19 as follows:

D.1.20 Reporting Requirements **[326 IAC 2-6.1-5 (a) (2)]**

13. Condition D.2.1 is changed to clarify that the limit as follows:

D.2.1 Particulate Matter Emissions (PM/PM_{10}) for Auxiliary Boiler [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the auxiliary boiler shall comply with the following:

(a) The PM ~~or~~ **and** PM_{10} emissions **each** from the auxiliary boiler shall not exceed 0.0075 lb/MMBtu on a higher heating value basis and shall not exceed 0.3 pounds per hour.

13. Condition D.2.3 is changed to remove the startup exception for opacity as the equipment uses natural gas as fuel as follows:

D.2.3 Opacity Limitations [326 IAC 2-2]

Pursuant to 326 IAC 2-2, the Permittee shall not cause the average opacity of the auxiliary boiler stack to exceed twenty percent (20%) in any one (1) six (6) minute period. ~~The opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.~~

14. Condition D.2.4 is changed to make the NOx pound per hour limit consisitent with the BACT determination for this unit as follows:

D.2.4 Nitrogen Oxide (NO_X) Emission Limitations for Auxiliary Boiler [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements), the auxiliary boiler shall comply with the following:

(a) The NOx emissions from the auxiliary boiler shall not exceed 0.049 lb/MMBtu on a higher heating value basis and shall not exceed ~~2.0~~ **1.9** pounds per hour.

15. The condition D.2.7 is changed to clarify that the BOIL 100 is not subject to the requirements of 326 IAC 8-1-6 because the potential VOC emissions are less than 25 tons per year.

D.2.7 Volatile Organic Compound (VOC) Emission Limitations for Auxiliary Boiler [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) ~~and 326 IAC8-1-6 (General Reduction Requirements)~~ the auxiliary boiler shall comply with the following:

16. The condition D.2.9, D.2.11 and D.2.12 are changed as follows to correct minor grammatical changes and add rule cites:

D.2.9 40 CFR Part 60 Subpart Dc (New Source Performance Standards for Small Industrial Commercial-Institutional Steam Generating Units)

Pursuant to New Source Performance Standards for Small Industrial Steam Generating Units the proposed auxiliary boiler is subject to the following requirements of Subpart Dc:

(a) Notification include the following information:

(1) The design heat input capacity, and to identify the types of fuels to be combusted.

(2) The anticipated annual operating hours based on each individual fuel fired.

(b) The owner or operator **shall** record and maintain records of the amounts of each fuel combusted during each day. All records required shall be maintained for a period of two (2) years following the date of such record.

D.2.11 Performance Testing

(a) For compliance purposes auxiliary boiler emissions shall be calculated using the emission factors for small boilers with low NO_X burners in USEPA's AP-42 Section 1.4 (07/1998) and the measured heating value.

(b) IDEM, OAQ retain**s** the authority under 326 IAC 2-1.1-8(f) to require the Permittee to perform additional and future compliance testing as necessary.

D.2.12 Record Keeping Requirements **[326 IAC 2-6.1-5 (a) (2)]**

(a) To document compliance with Condition D.2.8, the Permittee shall maintain records of the amount of natural gas combusted for ~~each~~ **the** auxiliary boiler during each month.

(b) All records shall be maintained in accordance with Section C – General Record Keeping Requirements.

D.2.13 Reporting Requirements **[326 IAC 2-6.1-5 (a) (2)]**

(a) The Permittee shall submit the following information on a quarterly basis: a summary of the information to document compliance with Condition D.2.8 shall be submitted to the addresses listed in Section C - General Reporting Requirements, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

17. The condition D.3.3 (Testing Requirement) does not form the part of the model conditions and therefore is completely deleted from the permit as follows:

~~Compliance Determination Requirements~~

~~D.3.3 Testing Requirements [326 IAC 2-1.1-11]~~

~~The Permittee is not required to test these emissions units by this permit. However, IDEM may require compliance testing when necessary to determine if the emissions unit is in compliance. If testing is required by IDEM, compliance shall be determined by a performance test conducted in accordance with Section C - Performance Testing.~~

18. The condition D.3.4 and D.3.5 are changed as follows to add rule cites:

D.3.4 Record Keeping Requirements **[326 IAC 2-6.1-5 (a) (2)]**

To document compliance with Conditions D.3.1 through D.3.3, the Permittee shall maintain records of the following:

(1) Amount of diesel fuel combusted each month in each black start generator.

(2) Amount of diesel fuel combusted each month in the fire pump.

(3) Amount of diesel fuel combusted each month in the emergency generator.

(4) The percent sulfur content of the diesel fuel.

D.3.5 Reporting Requirements **[326 IAC 2-6.1-5 (a) (2)]**

A quarterly summary of the information to document compliance with D.3.1 through D.3.3 shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

19. The quarterly report form for the startup and shutdown is revised as follows to clarify that the Permittee has to report the hours of startup and shutdown combined in a year.

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: Tenaska Indiana Partners L.P.
Location: County Road 625 East, Otwell, IN 47564
Permit No.: CP-125-12760-00039
Source: natural gas combustion turbines each operating in combined cycle (six (6) in number, please copy and use separate form for each turbine).
Limit: 650 hours for startup~~/~~ **and** shutdown in a 12 consecutive month period rolled on monthly basis

Year: ____________
Turbine ID: __________

Month	Column 1 ~~Events~~ **hours during startup and shutdown** ~~(~~ ~~T~~**t**his month~~)~~	Column 2 ~~Number of events~~ **hours during startup and shutdown during** previous 11 months	Column 1 + Column 2 ~~Number of events~~ **hours during startup and shutdown** for twelve month period
	Hours	Hours	Hours

No deviation occurred in this month

Deviation/s occurred in this month.
Deviation has been reported on:

Submitted by: ___________________________
Title/Position: ____
Signature: ____
Date: ____
Phone: ____

20. A new form for compliance monitoring report is added as shown on the next page:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

SEMI-ANNUAL DEVIATION AND COMPLIANCE MONITORING REPORT

Company Name: Tenaska Indiana Partners L.P.
Location: County Road 625 East, Otwell, IN 47564
Mailing Address: 1044 N.115 Street, Suite 400, Omaha NE 68154
Permit No.: CP-125-12760-00039

Months: ___________ **to** ____________ **Year:** ______________

Page 1 of 2

This report shall be submitted semi-annually based on a calendar year. Any deviation from the requirements, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. Deviations that are required to be reported by an applicable requirement shall be reported according to the schedule stated in the applicable requirement and do not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".
NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.
THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Form Completed By: ______________________________

Title/Position: ______________________________

Date: ______________________________

Phone: ______________________________

Attach a signed certification to complete this report.

Appendix A: Emissions Calculations
Summary of Emissions

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **25-Apr-02**

Potential to Emit Uncontrolled/Unlimited								
Pollutant	CC Turbine (tons/year)	CC Turbine SU/SD (tons/year)	Cooling Tower (tons/year)	Auxiliary Boiler	Black Start Generator	Emergency Generator	Fire Pump	Total (tons/year)
NOx	5216.61	307.188	-	8.58	2183.34	181.95	49.97	7947.64
CO	2226.74	4239.83	-	14.37	470.48	39.21	10.77	7001.38
VOC	378.29		-	0.95	177.07	14.76	4.05	575.11
SO2	347.42		-	0.10	144.38	12.03	12.03	515.97
H2SO4 Mist	212.87		-					212.87
PM/PM10	467.41		4.78	1.31	154.95	12.91	3.546	644.90
Formaldehyde*	8.62		-					8.62
Combined HAP*	22.28		-					22.28

Limited or Controlled PTE								
Pollutant	CC Turbine (tons/year)	CC Turbine SU/SD (tons/year)	Cooling Tower (tons/year)	Auxiliary Boiler	Black Start Generator	Emergency Generator	Fire Pump	Total (tons/year)
NOx	521.66	307.188	-	0.98	124.62	5.19	1.43	961.07
CO	822.77	4239.83	-	1.64	26.85	1.12	0.31	5092.52
VOC	378.29		-	0.11	10.11	0.42	0.12	389.04
SO2	347.42		-	0.01	8.24	0.34	0.34	356.36
H2SO4 Mist	212.87		-					212.87
PM/PM10	467.41		4.78	0.15	8.84	0.37	0.101	481.65
Formaldehyde*	8.62		-					8.62
Combined HAP*	22.28		-					22.28

*The HAP emissions from Duct Burner are exempt from case by case MACT determination pursuant to section 112 (g) as stated in Federal Register Vol. 65 No.102 dated May 25, 2000.

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **April 25, 2002**

Combined Cycle - Mitsubishi 501 F Combustion Turbines and Duct Burners
Combustion Turbine Potential to Emit Calculations - Before Controls or Federally Enforceable Limits

Combustion Turbine Heat input @ 59 F	**1821.80**	MMBtu/hr	@ HHV	Number of Turbines	**6**
Power Augmentation and Combustion Turbine Heat input @ 74 F	**2112.00**	MMBtu/hr	@ HHV		
Duct Burner Heat input	**550**	MMBtu/hr	@ HHV	Number of Duct Burners	**6**

	Normal Operation	Startup/Shutdown
Turbine Operation (hrs/yr)	**6518**	**742**
Duct Burner Operation (hrs/yr)	**6518**	
Turbine and Duct Burner operation with Power Augmentation (hrs/yr) at 74 F	**1500**	

Combined Combustion Turbine and Duct Burner Emissions

Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	2371.80 MMBtu/hr	0.0906 lb/MMBtu	215.00	700.69 tons/yr	4204.11 tons/yr
CO	2371.80 MMBtu/hr	0.0198 lb/MMBtu	47.00	153.17 tons/yr	919.04 tons/yr
VOC	2371.80 MMBtu/hr	0.0051 lb/MMBtu	12.10	43.92 tons/yr	263.54 tons/yr
SO_2	2371.80 MMBtu/hr	0.0055 lb/MMBtu	13.10	47.55 tons/yr	285.32 tons/yr
H2SO4 Mist*	2371.80 MMBtu/hr	0.0034 lb/MMBtu	8.10	29.40 tons/yr	176.42 tons/yr
PM_{10}**	2371.80 MMBtu/hr	0.0075 lb/MMBtu	17.70	64.25 tons/yr	385.51 tons/yr

Power Augmentation for Combustion Turbine and Duct Buner Emissions

Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	2662.00 MMBtu/hr	0.0845 lb/MMBtu	225.00	168.75 tons/yr	1012.50 tons/yr
CO	2662.00 MMBtu/hr	0.1092 lb/MMBtu	290.60	217.95 tons/yr	1307.70 tons/yr
VOC	2662.00 MMBtu/hr	0.0096 lb/MMBtu	25.50	19.13 tons/yr	114.75 tons/yr
SO_2	2662.00 MMBtu/hr	0.0052 lb/MMBtu	13.80	10.35 tons/yr	62.10 tons/yr
H2SO4 Mist*	2662.00 MMBtu/hr	0.0030 lb/MMBtu	8.10	6.08 tons/yr	36.45 tons/yr
PM10**	2662.00 MMBtu/hr	0.0068 lb/MMBtu	18.20	13.65 tons/yr	81.90 tons/yr

Total uncontrolled Potential Emissions from Combustion Turbines and Duct Burners

Pollutant	Total PTE
NO_X	5216.61 tons/yr
CO	2226.74 tons/yr
VOC	378.29 tons/yr
SO_2	347.42 tons/yr
H2SO4 Mist*	212.87 tons/yr
PM10**	467.41 tons/yr

Combustion turbine emission factors are vendor provide data

Calculations are based on 8760-SU/SD hours per year of operation (Normal Opeartion + Startup/Shutdown = 8760 hrs/yr)

*due to lack of more accurate emission factors, the H2SO4 mist emission factor is assumed same with or without power augmentation

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **April 25, 2002**

Combined Cycle - Mitsubishi 501 F Combustion Turbines and Duct Burners
Combustion Turbine Potential to Emit Calculation - After Control or Federally Enforceable Limits

Combined Combustion Turbine and Duct Burner Emissions					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	2371.8 MMBtu/hr	0.0091 lb/MMBtu	21.50	70.07 tons/yr	420.41 tons/yr
CO	2371.8 MMBtu/hr	0.0119 lb/MMBtu	28.20	91.90 tons/yr	551.42 tons/yr
VOC	2371.8 MMBtu/hr	0.0051 lb/MMBtu	12.10	43.92 tons/yr	263.54 tons/yr
SO_2	2371.8 MMBtu/hr	0.0055 lb/MMBtu	13.10	47.55 tons/yr	285.32 tons/yr
H2SO4 Mist*	2371.8 MMBtu/hr	0.0034 lb/MMBtu	8.10	29.40 tons/yr	176.42 tons/yr
PM_{10}**	2371.8 MMBtu/hr	0.0075 lb/MMBtu	17.70	64.25 tons/yr	385.51 tons/yr

Power Augmentation for Combustion Turbine and Duct Buner Emissions					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	2662.00 MMBtu/hr	0.0085 lb/MMBtu	22.50	16.88 tons/yr	101.25 tons/yr
CO	2662.00 MMBtu/hr	0.0227 lb/MMBtu	60.30	45.23 tons/yr	271.35 tons/yr
VOC	2662.00 MMBtu/hr	0.0096 lb/MMBtu	25.50	19.13 tons/yr	114.75 tons/yr
SO_2	2662.00 MMBtu/hr	0.0052 lb/MMBtu	13.80	10.35 tons/yr	62.10 tons/yr
H2SO4 Mist*	2662.00 MMBtu/hr	0.0030 lb/MMBtu	8.10	6.08 tons/yr	36.45 tons/yr
PM10**	2662.00 MMBtu/hr	0.0068 lb/MMBtu	18.20	13.65 tons/yr	81.90 tons/yr

Total uncontrolled Potential Emissions from Combustion Turbines and Duct Burners	
Pollutant	Total PTE
NO_X	521.66 tons/yr
CO	822.77 tons/yr
VOC	378.29 tons/yr
SO_2	347.42 tons/yr
H2SO4 Mist*	212.87 tons/yr
PM10**	467.41 tons/yr

Note - All emission rates are based on vendor provided data. The Permittee will be required to Stack test for all criteria pollutants to show that the actual emission rates are equal to or less than shown above.

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **April 25, 2002**

Startup/Shutdown Emissions

Combined Cycle Operation - Mitsubishi 501 F

	Hot	Warm	Cold
Estimated max startups per year	**70**	**70**	**70**
Startup duration (hours)	**1.28**	**2.37**	**4.95**
Total startup hours in a year			**602**
Estimated max shutdowns per year	**70**	**70**	**70**
Shutdown duration (hours)	**0.67**	**0.67**	**0.67**
Total shutdown hours in a year			**140**

Emissions from Combined Cycle Opeartion						
Pollutant	Type	Duration (hours)	Startup Emission Rate per turbine (lb/Startup)	Shutdown Emission Rate per turbine (lb/shutdown)	Emission Rate/turbine (tons/yr)	Total Emission Rate based startup of all turbine (tons/yr)
NO_X	Hot	1.28	182.0	49.6	8.11	48.64
	Warm	2.37	354.0	49.6	14.13	84.76
	Cold	4.95	778.0	49.6	28.97	173.80
Total NOx per year					51.2	307.19
CO	Hot	1.28	1294.0	712.0	45.31	271.88
	Warm	2.37	4625.0	712.0	186.80	1120.77
	Cold	4.95	12846.0	712.0	474.53	2847.18
Total CO per year					706.64	4239.83

*Emission rate/Turbine (tpy) includes both the startup and shutdown
Emission rates provided by the vendor

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: Tenaska Indiana Partners, LP
Address City IN Zip: County Road 625 East, Otwell, IN 47564
CP: 125-12760
Plt ID: 125-00039
Reviewer: GS
Date: April 25, 2002

Combustion Turbines and Duct Burners Potential to Emit Calculations for HAPs

	Duct Burner				Combustion Turbine				Total HAPs CT + DB
HAPs	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr)	ton/yr @8760 hrs/yr (x6)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr)	ton/yr @ 8760 hrs/yr (x6)	tons/yr
Benzene	2.06E-06	1.13E-03	4.96E-03	2.98E-02	1.20E-05	1.35E-01	5.90E-01	3.54E+00	3.57E+00
Dichlorobenzene	1.18E-06	6.47E-04	2.83E-03	1.70E-02				0.00E+00	1.70E-02
Formaldehyde*	7.35E-05	4.04E-02	1.77E-01	1.06E+00	1.58E-04	2.88E-01	1.26E+00	7.56E+00	8.62E+00
Xylenes					6.40E-05	1.35E-01	5.92E-01	3.55E+00	3.55E+00
Hexane**	1.48E-04	8.14E-02	3.57E-01	2.14E+00					2.14E+00
Ethylbenzene					3.20E-05	6.76E-02	2.96E-01	1.78E+00	1.78E+00
1,3 Butadiene					4.30E-07	9.08E-04	3.98E-03	2.39E-02	2.39E-02
Napthalene	5.98E-07	3.29E-04	1.44E-03	8.64E-03	1.30E-06	2.75E-03	1.20E-02	7.22E-02	8.08E-02
Toluene	3.33E-06	1.83E-03	8.03E-03	4.82E-02	1.30E-04	4.89E-02	2.14E-01	1.29E+00	1.33E+00
PAH					2.20E-06	4.65E-03	2.04E-02	1.22E-01	1.22E-01
POM	8.65E-08	4.76E-05	2.08E-04	1.25E-03					1.25E-03
Acetaldehyde					4.00E-05	3.67E-02	1.61E-01	9.65E-01	9.65E-01
Arsenic	1.96E-07	1.08E-04	4.72E-04	2.83E-03					2.83E-03
Beryllium	1.18E-08	6.47E-06	2.83E-05	1.70E-04					1.70E-04
Cadmium	1.08E-06	5.93E-04	2.60E-03	1.56E-02					1.56E-02
Chromium	1.37E-06	7.55E-04	3.31E-03	1.98E-02					1.98E-02
Cobalt	8.24E-08	4.53E-05	1.98E-04	1.19E-03					1.19E-03
Manganese	3.73E-07	2.05E-04	8.97E-04	5.38E-03					5.38E-03
Mercury	2.55E-07	1.40E-04	6.14E-04	3.68E-03					3.68E-03
Nickel	2.06E-06	1.13E-03	4.96E-03	2.98E-02					2.98E-02
Selenium	2.35E-08	1.29E-05	5.67E-05	3.40E-04					3.40E-04
single HAP			0.36	2.14			1.26	7.56	8.62
combined HAP			0.56	3.39			3.15	18.89	22.28

HAPs emission factors for the turbines are from AP-42 Table 3.1-3

HAPs emission factors for the duct burners are from AP-42 Table 1.4-3

*based on applicant's recommendation, the formaldehyde emission factor for gas turbine is calculated by multiplying EPRI study factor by 4.0. This is comparable to stack test for similar size turbine presented by the applicant as part of the application. For Duct Burners it is standard AP 42 emission factor

Appendix A: Emissions Calculations
Auxillary Boiler Emissions
MM BTU/HR <100
Small Industrial Boiler

Company Name: Tenaska Indiana Partners, LP
Address City IN Zip: County Road 625 East, Otwell, IN 47564
CP: 125-12760
Plt ID: 125-00039
Reviewer: GS
Date: 25-Apr-02

Natural Gas Utility Boiler Calculation

Auxiliary Boiler Heat Input Rate: 40 MMBtu/hr

Number of Boilers: 1

Boiler Operation (hrs/yr): 1000

Annual gas usage (MMSCF): 38.1

Auxiliary Boiler									
Pollutant	Heat Input		Emission Factor		lb/hr	Boiler PTE		PTE after Control or Enforcable Limits	
NO_X	40	MMBtu/hr	4.90E-02	lb/MMBtu	1.960	8.585	ton/yr	0.980	ton/yr
CO	40	MMBtu/hr	8.20E-02	lb/MMBtu	3.280	14.366	ton/yr	1.640	ton/yr
VOC	40	MMBtu/hr	5.40E-03	lb/MMBtu	0.216	0.946	ton/yr	0.108	ton/yr
SO_2	40	MMBtu/hr	5.88E-04	lb/MMBtu	0.024	0.103	ton/yr	0.012	ton/yr
PM_{10}	40	MMBtu/hr	7.50E-03	lb/MMBtu	0.300	1.314	ton/yr	0.150	ton/yr

*Emission factors are from AP-42 Table 1.4-2 utilizing Low NOx Burners
*Emission factors are based on a heating value of natural gas of 1050 Btu/scf

Pollutant	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE Before Control (tpy)	PTE After Control or Enforceable Limit (tpy)
Benzene	2.10E-03	2.00E-06	8.00E-05	3.50E-04	4.00E-05
Diclorobenzene	1.20E-03	1.14E-06	4.57E-05	2.00E-04	2.29E-05
Formaldehyde	7.50E-02	7.14E-05	2.86E-03	1.25E-02	1.43E-03
Hexane	1.80E+00	1.71E-03	6.86E-02	3.00E-01	3.43E-02
Napthalene	6.10E-04	5.81E-07	2.32E-05	1.02E-04	1.16E-05
Toluene	3.40E-03	3.24E-06	1.30E-04	5.67E-04	6.48E-05
POM	8.87E-05	8.45E-08	3.38E-06	1.48E-05	1.69E-06
Arsenic	2.00E-04	1.90E-07	7.62E-06	3.34E-05	3.81E-06
Beryllium	1.20E-05	1.14E-08	4.57E-07	2.00E-06	2.29E-07
Cadmium	1.10E-03	1.05E-06	4.19E-05	1.84E-04	2.10E-05
Chromium	1.40E-03	1.33E-06	5.33E-05	2.34E-04	2.67E-05
Cobalt	8.40E-05	8.00E-08	3.20E-06	1.40E-05	1.60E-06
Manganese	3.80E-04	3.62E-07	1.45E-05	6.34E-05	7.24E-06
Mercury	2.60E-04	2.48E-07	9.90E-06	4.34E-05	4.95E-06
Nickel	2.10E-03	2.00E-06	8.00E-05	3.50E-04	4.00E-05
Selenium	2.40E-05	2.29E-08	9.14E-07	4.00E-06	4.57E-07
		Single HAP		**3.00E-01**	**3.43E-02**
		Combined HAP		**3.15E-01**	**3.60E-02**

*HAPs emission factors based on AP-42 1.4-3

Appendix A: Emissions Calculations
Cooling Tower Emissions

Company Name: Tenaska Indiana Partners, LP
Address City IN Zip: County Road 625 East, Otwell, IN 47564
CP: 125-12760
Plt ID: 125-00039
Reviewer: GS
Date: April 25, 2002

Cooling Tower Emissions

	Value	Unit	Calculation
Flow of Water at 100% Load	278480	gpm	vendor information
Cooling Water Flowrate	139351392	lb/hr	Flowrate (gal/min) * 8.34 lb/gal * 60 min/hr
Total Disolved Solids (TDS)	1566	ppm	vendor information
Cooling Water TDS Fraction	0.001566	lb TDS/lb	TDS/10^6 lb/ppm
Drift Loses (% of cooling water)	0.0005	%	vendor information
Liquid Drift Losses	696.757	lb/hr	Cooling water flow rate lb/hr * 0.001/100
Solids Drift Losses	1.091	lb/hr	Liquid Drift Losses * TDS Fraction lb TDS/lb
PM_{10}/TSD Emission	4.779	ton/yr	

Appendix A: Emissions Calculations
Black-Start Generator

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **April 25, 2002**

Number of Generators 6

Heat Input Capacity Horsepower (hp)	Potential Throughput hp-hr/yr	Potential Throughput at 500 Limited hour per Generator per year hp-hr/yr
2680	23476800	1340000

	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.00205	0.031	0.0025141	0.00668
Potential Emission in tons/yr	154.95	154.95	144.38	2183.34	177.07	470.48
Limited Potential Emission in tons/yr	8.84	8.84	8.24	124.62	10.11	26.85

Fuel Limit per Generator = 94733 gallons of diesel

Methodology

Potential Througput (hp-hr/yr) = hp * 8760 hr/yr
Use a conversion factor of 7,000 Btu per hp-hr to convert from horsepower to Btu/hr, unless the source gives you a source-specific brake-specific fuel consumption. (AP-42, Footnote a, Table 3.3-1)
Emission Factors are from AP42 (Supplement B 10/96), Table 3.3-2
Emission (tons/yr) = [Potential Throughput (hp-/hr/yr) x Emission Factor (lb/hp-hr)] / (2,000 lb/ton)

Appendix A: Emissions Calculations
Emergency Generator

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **April 25, 2002**

Heat Input Capacity Horsepower (hp)	Potential Throughput hp-hr/yr	Potential Throughput at hp-hr/yr	250 Limited hour per year
1340	11738400	335000	

	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.00205	0.031	0.0025141	0.00668
Potential Emission in tons/yr	12.91	12.91	12.03	181.95	14.76	39.21
Limited Potential Emission in tons/yr	0.37	0.37	0.34	5.19	0.42	1.12

Fuel Limit per Generator = 23683 gallons of diesel

Methodology

Potential Througput (hp-hr/yr) = hp * 8760 hr/yr
Use a conversion factor of 7,000 Btu per hp-hr to convert from horsepower to Btu/hr, unless the source gives you a source-specific brake-specific fuel consumption. (AP-42, Footnote a, Table 3.3-1)
Emission Factors are from AP42 (Supplement B 10/96), Table 3.3-2
Emission (tons/yr) = [Potential Throughput (hp-/hr/yr) x Emission Factor (lb/hp-hr)] / (2,000 lb/ton)

Appendix A: Emissions Calculations
Emergency Generator

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **April 25, 2002**

Heat Input Capacity Horsepower (hp)	Potential Throughput hp-hr/yr	Potential Throughput at hp-hr/yr	250 Limited hour per year
368	3223680	92000	

	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.00205	0.031	0.0025141	0.00668
Potential Emission in tons/yr	3.55	3.55	3.30	49.97	4.05	10.77
Limited Potential Emission in tons/yr	0.10	0.10	0.09	1.43	0.12	0.31

Fuel Limit per Generator = 6504 gallons of diesel

Methodology

Potential Througput (hp-hr/yr) = hp * 8760 hr/yr
Use a conversion factor of 7,000 Btu per hp-hr to convert from horsepower to Btu/hr, unless the source gives you a source-specific brake-specific fuel consumption. (AP-42, Footnote a, Table 3.3-1)
Emission Factors are from AP42 (Supplement B 10/96), Table 3.3-2
Emission (tons/yr) = [Potential Throughput (hp-/hr/yr) x Emission Factor (lb/hp-hr)] / (2,000 lb/ton)

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for New Construction and Prevention of Significant Deterioration Permit

Source Background and Description

Source Name:	Tenaska Indiana Partners, L.P.
Source Location:	County Road 625 East, Otwell, IN 47564
County:	Pike
Construction Permit No.:	CP-125-12760-00039
SIC Code:	4911
Permit Reviewer:	Gurinder Saini

The Office of Air Quality (OAQ) has reviewed an application from Tenaska Indiana Power Partners, L.P. relating to the construction and operation of an 1,800 MW natural-gas-fired combined-cycle power plant, Tenaska Indiana Generating Station. The source will fire only natural gas. Any addition of a backup fuel in the future will require a permit modification and Prevention of Significant Deterioration (PSD) review, if applicable. The source will consist of the following equipment:

(a) Six (6) natural-gas-fired combustion turbines designated as units GT-1 through GT-6 with a maximum heat input capacity of 2,112 MMBtu/hr higher heating value (HHV) per unit. Six (6) heat recovery steam generators, designated as units HRSG-1 through HRSG-6 with six (6) associated duct burners. Each duct burner is rated at a maximum heat input of 550 MMBtu/hr HHV per unit and exhausts to stack designated ST-1 through ST-6. The emissions from the natural-gas-fired combustion turbines and duct burners are controlled using Selective Catalytic Reduction (SCR) Systems, low-NO_X combustors and burners, combustion controls, and the use of clean burning natural gas as a fuel.

(b) Two (2) reheat condensing steam turbines.

(c) One (1) auxiliary boiler, designated as Boil with maximum heat input rating of 40 MMBtu/hr and exhausting to a stack designated as BOIL 100.

(d) Two (2) cooling towers, designated as Cool-1 and Cool-2 and exhausting to stacks designated as Cool – 1 and Cool - 2.

(e) Six (6) black-start diesel generators, designated as BSG1 through BSG6, with a maximum heat input of 19.1 MMBtu/hr HHV utilizing low sulfur diesel fuel and exhausting to stacks designated BSG-1 through BSG-6

(f) One (1) emergency diesel generator, designated as AUG-1, with a maximum heat input capacity of 10.1 MMBtu/hr HHV utilizing low sulfur diesel fuel and exhausting to a stack designated as Emergency.

(g) One (1) diesel fire pump, designated as DFP-1, with a maximum rated heat input capacity of 0.95 MMBtu/hr utilizing low sulfur diesel fuel and exhausting to a stack designated as Fire Pump.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (^{0}F)
ST1 – ST6	Gas Turbine Exhaust (6)	170	18	1,153,000 (each)	200
BSG-1 - BSG-6	Blackstart Generator (6)	25	1	15,839 (each)	950
Emergency	Emergency Generator	25	0.667	7,571	814
Fire Pump	Diesel Fire Pump	25	0.5	2,594	830
Cooling	Cooling Tower (2)	55	32 (each cell)	1,614,642 (each cell)	105

Recommendation

The staff recommends to the Commissioner that the construction and operation be approved. This recommendation is based on the following facts and conditions:

Information used in this review, unless otherwise stated, was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on October 3, 2000, with additional information received on October 11, 2000, December 20, 2000, January 17, 2001, February 19, 2001, March 3, 2001 June 11, 2001, July 5, 2001 and May 9, 2002.

Emissions Calculation

See Appendix (Emission Calculation Spreadsheets for detailed calculations **(ten (10) pages**). Criteria pollutant emission rates from the turbines are based on Mitsubishi Heavy Industries vendor data or Supplement F of EPA AP-42 (4/00) emission factors from Chapter 3.1 (Stationary Gas Turbines for Electricity Generation) utilizing 100 percent natural gas. Criteria pollutant emission rates from the duct burners are based on vendor data or EPA AP-42 emission factors from Chapter 1.4 (Natural Gas Combustion from Boilers) utilizing 100 percent natural gas. It also should be noted that the emission factors, heat input and heat content values are based on the higher heating value (HHV). The HHV includes the energy released by condensing the water formed in the combustion reaction.

Emissions associated with startup/shutdown periods are higher than emissions associated with steady state conditions of the turbines. Therefore, the calculations for the potential to emit (PTE) also include the startup/shutdown emissions. The permit also contains separate conditions for periods of startup and shutdown.

Hazardous Air Pollutant (HAPs) emission calculations are based on Supplement F of EPA AP-42 (4/00) emission factors from Chapter 3.1 (Stationary Gas Turbines for Electricity Generation). The HAP emission rates from the duct burners, auxiliary boilers and water bath gas heater are based on EPA AP-42 emission factors from Chapter 1.4 (Natural Combustion from Boilers). HAP emissions from the emergency support equipment are anticipated to be negligible, thus have not been quantified.

Potential to Emit of Source before Controls and Enforceable limits

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as Athe maximum capacity of a stationary source or emissions unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, the department, or the appropriate local air pollution control agency".

Pollutant	Potential To Emit (tons/year)
PM	644.9
PM-10	644.9
SO_2	516.0
VOC	575.1
CO	5914.2
NO_x	7947.6

HAP=s	Potential To Emit (tons/year)
Formaldehyde	8.62
Total HAPs	22.28

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM, PM-10, SO_2, VOC and NOx are greater than 25 tons per year and of CO is greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-5.1-3.

(b) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM, PM-10, SO_2, VOC, CO and NOx is greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

(c) Fugitive Emissions
Since this type of operation is one of the twenty-eight (28) listed source categories under 326 IAC 2-2, the fugitive emissions are counted toward determination of PSD applicability.

County Attainment Status

The source is located in Pike County.

Pollutant	Status
PM_{10}	Attainment
SO_2	Attainment
NO_2	Attainment
Ozone	Attainment
CO	Attainment
Lead	Attainment

(a) Volatile organic compounds (VOC) are precursors for the formation of ozone. Therefore, VOC emissions are considered when evaluating the rule applicability relating to the ozone standards. Pike County has been designated as attainment or unclassifiable for ozone. Therefore, VOC emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

(b) Pike County has been classified as attainment or unclassifiable for SO_2, PM, PM_{10} and CO. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

Source Status

New Source PSD Definition (emissions after controls, based on 8,760 hours of operation per year at rated capacity and/ or as otherwise limited):

Pollutant	Emissions (ton/yr)	Significance Threshold Levels (tons/year)
PM	481.6	25
PM10	481.6	15
SO_2	356.4	40
H_2SO_4 Mist	212.9	7
VOC	389.0	40
CO	5409.3	100
NO_x	961.1	40

(a) This Source is major for PM, PM_{10}, VOC, CO, SO_2, H_2SO_4, and NOx emissions.

(b) The NO_X emissions from the combustion turbine and duct burner shall be controlled by a dry low NOx combustion system for the gas turbine, low NOx duct burners and selective catalytic reduction (SCR) system.

(c) The CO emissions from the combustion turbine and duct burner shall be controlled by using dry low NO_x combustion system and good combustion practices. A catalytic oxidation system will be installed if the emission limitations established for the turbine and duct burner can not be achieved with the dry low NO_x combustion system and good combustion practices.

(d) The combined-cycle power plant is a major stationary source because at least one regulated pollutant is emitted above its associated major source threshold level. Also the proposed facility is classified as a “fossil fuel-fired steam electric plant of more than 250 MMBtu per hour” and is therefore one of the 28 listed categories, as stated in 326 IAC 2-2.

Part 70 Permit Determination

326 IAC 2-7 (Part 70 Permit Program)

This new source is subject to the Part 70 Permit requirements because the potential to emit (PTE) of:

(a) at least one of the criteria pollutant is greater than or equal to 100 tons per year,

This new source shall apply for a Part 70 (Title V) operating permit within twelve (12) months after this source becomes subject to requirements of Part 70 Operating Permit.

Acid Rain Permit Applicability [326 IAC 2-7-2]

This stationary source shall be required to have a Phase II, Acid Rain permit in accordance with 40 CFR 72.30 (Applicability) because:

(a) The combustion turbines are new units under 40 CFR 72.6.

(b) The source cannot operate the combustion units until their Phase II, Acid Rain permit application has been submitted to the appropriate regulatory authority.

Federal Rule Applicability

40 CFR 60, Subpart GG (Stationary Gas Turbines)

The six (6) natural gas combustion turbines are subject to the New Source Performance Standard (NSPS) for Stationary Gas Turbines (40 CFR Part 60, Subpart GG) because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour (10 MMBtu per hour), based on the lower heating value of the fuel fired.

Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) limit nitrogen oxides emissions to 0.0113% by volume at 15% oxygen on a dry basis, as required by 40 CFR 60.332, to:

$$STD = 0.0075 \frac{(14.4)}{Y} + F,$$

where STD = allowable NO_x emissions (percent by volume at 15 percent oxygen on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) Limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight;

(3) Install a continuous monitoring system to monitor and record the fuel consumption as required by 40 CFR 60.334(a);

(a) Monitor the sulfur content and nitrogen content of the fuel being fired in the turbine, as required by 40 CFR 60.334(b); and

(5) Report periods of excess emissions, as required by 40 CFR 334(c).

40 CFR Part 60, Subpart Da (Electric Utility Steam Generating Units)

The heat recovery steam generator (HRSG) duct burners (DB) are subject to 40 CFR Part 60, Subpart Da because the heat input capacity is greater than 250 MMBtu/hr. The HRSG DBs have a heat input capacity of 550 MMBtu/hr higher heating value (HHV) and are therefore subject to Subpart Da.

Pursuant to 40 CFR Part 60, Subpart Da, the Permittee shall:

(a) Limit DB particulate matter (PM) emissions to no more than 9.0 lb/hr during normal operation, as required by 40 CFR 60.42(a)

(b) 40 CFR 60.42a(b) sets the maximum opacity to twenty percent (20%) for a six (6) minute average, except for one six (6) minute period per hour of not more than twenty seven percent (27%).

(c) Limit DB NO_X emissions to no more than 60 lb/hr during normal operation, as required by 40 CFR 60.44a(a)(1). Demonstration with the NSPS emission standard also demonstrates compliance with NO_X emissions reduction requirements, as stated in 40 CFR 60.44a(a)(2)

(d) A continuous monitoring system is required to record NO_X emissions from each duct burner (DB), as required by 40 CFR 60.47a(c).

(e) As required by 40 CFR 60.47a(d) continuous monitoring system must be installed to record oxygen (O_2) or carbon dioxide (CO_2) concentrations at each location where NO_x emissions are measured.

(f) The natural-gas-fired duct burners, as required by 40 CFR 60.46a, are subject to the following:

(1) The particulate matter emission standards and nitrogen oxide standards apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide standards apply at all times except during periods of startup or shutdown.

(2) After the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide and nitrogen oxide emission limitations are based on the average emission rate for thirty (30) successive burner operating days. A separate performance test is completed at the end of each burner operating day after the initial performance test, and a new thirty (30) day average emission rate for both sulfur oxide dioxide and nitrogen oxides; and

(3) For the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide and nitrogen oxide emission limitations are based on the average emission rates for the first thirty (30) successive burner operating days. The initial performance test is the only test in which at least thirty (30) days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first burner operating day of the thirty (30) successive boiler operating days is completed within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the facility.

(g) The duct burners are not subject to the opacity and sulfur dioxide (SO_2) emission monitoring, 40 CFR 60.47a(a) and (b) requirements because only natural gas fuel is combusted.

(h) The Permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxide (NO_X) emissions discharged to the atmosphere, as required by 40 CFR 60.47a(c).

(i) The Permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring oxygen content of the flue gases at each location where nitrogen oxide (NO_X) emissions are monitored, as required by 40 CFR 60.47(d).

(j) The Permittee shall use as use Method 19 to determine the emission rate of NO_X, and the continuous monitoring system shall be used to determine concentrations of NO_X and O_2, as required by 40 CFR 60.48a.

(k) The Permittee, as required by 40 CFR 60.49a(Reporting Requirements), is subject to the following reporting requirements:

(1) NO_X performance test data from the initial performance test and from the performance evaluation of the continuous monitoring are submitted to the Administrator.

(2) Information required by 40 CFR 60.49a(b) from the NO_X CEM for each 24-hour period.

(3) Information required by 40 CFR 60.49a(c) when the minimum quantity of emission data is not obtained for any thirty (30) successive burner operating days.

(4) For any period in which nitrogen oxide (NO_X) emission data is not available, the Permittee shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(5) The Permittee shall submit a signed statement, as required by 40 CFR 60.49a(g) indicating whether:

(a) The required CEM calibration, span, drift checks or other periodic audits have of have not been performed as specified.

(b) The data used to show compliance was of was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(c) The minimum data requirements have not been met; or, the minimum data requirements have not been met for errors that where unavoidable.

(d) Compliance with the standards has not been achieved during the reporting period.

(6) For the purpose of the reports required under 40 CFR 60.7, periods of excess emissions are defined as all six (6) minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR 42a(b). Opacity levels in excess of the applicable opacity standard and the dates of such excesses are submitted to the Administrator each calendar quarter.

(7) The Permittee shall submit the written reports to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30^{th} day following at the end of each calendar quarter.

40 CFR Part 60 Subpart Db (New Source Performance Standards for Industrial Steam Generating Units)

The proposed plant is not subject to the New Source Performance Standards (NSPS) for Industrial Steam Generating Units because the proposed plant is subject to the requirements of 40 CFR 60 Subpart Da. According to 40 CFR 60.40b(e) (Applicability Requirements), steam generating units meeting the applicability requirements of 40 CFR 60 Subpart Da are not subject to this subpart.

40 CFR Part 60 Subpart Dc (New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units)

Pursuant to New Source Performance Standards for Small Industrial Steam Generating Units any steam generating units that have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. The proposed auxiliary boiler has a maximum rated heat input capacity of 40 MMBtu/hr and is therefore subject to the following requirements of Subpart Dc:

(a) Notification include the following information:

(1) The design heat input capacity, and to identify the types of fuels to be combusted.

(2) The anticipated annual operating hours based on each individual fuel fired.

(b) The owner or operator record and maintain records of the amounts of each fuel combusted during each day. All records required shall be maintained for a period of two (2) years following the date of such record.

40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants)

Presently, there are no proposed or final National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for electric utility steam generating units.

State Rule Applicability

326 IAC 1-5-2 and 326 IAC 1-5-3 (Emergency Reduction Plans)

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall prepare written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) These ERPs shall be submitted for approval to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

within 180 days from the date on which this source commences operation.

(c) If the ERP is disapproved by IDEM, OAQ, the Permittee shall have an additional thirty (30) days to resolve the differences and submit an approvable ERP. If after this time, the Permittee does not submit an approvable ERP, then IDEM, OAQ shall supply such a plan.

(d) These ERPs shall state those actions that will be taken, when each episode level is declared, to reduce or eliminate emissions of the appropriate air pollutants.

(e) Said ERPs shall also identify the sources of air pollutants, the approximate amount of reduction of the pollutants, and a brief description of the manner in which the reduction will be achieved.

(f) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-3 (Implementation of ERP), the Permittee shall put into effect the actions stipulated in the approved ERP upon direct notification by OAQ that a specific air pollution episode is in effect.

326 IAC 1-6-3 (Preventive Maintenance)

(a) The Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days after issuance of this permit, including the following information on each:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission units;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions.

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

(b) The Permittee shall implement the Preventive Maintenance Plans as necessary to ensure that lack of proper maintenance does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) PMP's shall be submitted to IDEM, OAQ upon request and shall be subject to review and approval by IDEM, OAQ.

326 IAC 1-7 (Stack Height Provisions)

Stacks are subject to the requirements of 326 IAC 1-7 (Stack Height Provisions) because the potential emissions which exhaust through the above-mentioned stacks, are greater than 25 tons per year of PM and SO_2. This rule requires that the stack be constructed using Good Engineering Practice (GEP) unless field studies or other methods of modeling show to the satisfaction of IDEM that no excessive ground level concentrations, due to less than adequate stack height, will result.

The height of the proposed stack will be less than the GEP stack height. Therefore, a dispersion model to determine the significant ambient air impact area was developed and an analysis of actual stack height with respect to GEP was performed. Appendix B discusses the results of these modeling exercises.

326 IAC 2-2 (Prevention of Significant Deterioration)

This new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, NO_X , H_2SO_4 Mist and VOC because the potential to emit for these pollutants exceeds the PSD major "significant" thresholds, as specified in 326 IAC 2-2-1.
Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standard (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

The attached modeling analysis, included in Appendix B, was conducted to show that the new source does not violate the NAAQS and does not exceed the incremental consumption above eighty percent (80%) of the PSD increment for any affected pollutant.

The BACT Analysis Report, included in Appendix C, was conducted for the major source PSD pollutants for each process on a case-by-case basis by reviewing similar process controls and new available technologies. The BACT determination is based on the cost-per-ton of pollutant removed, energy requirements, and environmental impacts. The following BACT emission limitations apply to the proposed source:

Pollutant	Combustion Turbine	Limit (ppmvd @ 15% O_2)	Combustion Turbines and Duct Burners	Limit (ppmvd @ 15% O_2)	Event (one Startup and one Shutdown)	Limit per turbine (lb/event)
NO_X	Dry Low-NOx Combustors and SCR	2.5 (3 hour block avg.)	Dry Low-NOx Combustors and SCR	2.5 (3 hour block avg.)	Limited to 4.95 hours per event per turbine and Duct Burners not operated until normal operation begins	827
CO	Good Combustor Design and Combustion Control / CO Oxidation Catalyst	6.0 (24 hour block average)	Good Combustor design and Combustion Control, Oxidation Catalyst (if required)	9.0 (24 hour block average)	Same as above	13,558
			During Power Augmentation use Good Combustor control and Combustion Control, Oxidation Catalyst (if required)	53.0 (3 hour block average)		
VOC	Good Combustion Control	0.0015 lb/MMBtu	Good Combustion Control, Oxidation Catalyst (if required)	0.0051 lb/MMBtu	N/A	N/A
			During Power Augmentation mode use Good Combustion Control, Oxidation Catalyst (if required)	0.01 lb/MMBtu		
SO_2	Natural Gas as Sole Fuel	0.0055 lb/MMBtu	Natural Gas as Sole Fuel	0.0055 lb/MMBtu	N/A	N/A
H_2SO_4 Mist	Natural Gas as Sole Fuel	0.0034 lb/MMBtu	Natural Gas as Sole Fuel	0.0034 lb/MMBtu	N/A	N/A
PM/PM_{10}	Natural Gas as Sole Fuel and Good Combustion Practice	0.005 lb/MMBtu	Natural Gas as Sole Fuel and Good Combustion Practice	0.0075 lb/MMBtu	N/A	N/A
Opacity	Natural Gas as Sole Fuel and Good Combustion Practice	20%	Natural Gas as Sole Fuel and Good Combustion Practice	20%	N/A	N/A

Pollutant	Auxiliary Boiler	Limit (lb/MMBtu)	Cooling Towers	Limit
NO_X	Natural Gas as Sole Fuel and Low NOx Combustors, 1000 hours of operation per year	0.049	N/A	N/A
CO	Good Combustion Practice	0.082	N/A	N/A
VOC	Good Combustion Practice	0.0054	N/A	N/A
SO_2	Natural Gas as Sole Fuel	0.0006	N/A	N/A
PM/PM_{10}	Natural Gas as Sole Fuel and Good Combustion Practice	0.0075	Drift Eliminators	1.1 lb/hour
Opacity	Good Combustion Practice	20%		20%

Black Start Generators, Emergency Generator and Fire Water Pump
The BACT is as follows:

1. The total fuel input for each black start generator shall not exceed 94,733 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

2. The total fuel input for the fire pump shall not exceed 6,504 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

3. The total fuel input for the emergency generator shall not exceed 23,683 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

4. The sulfur content of the diesel fuel used by the emergency generator shall not exceed 0.05 percent by weight.

5. Perform good combustion practice.

326 IAC 2-4.1-1 (Major Source of Hazardous Air Pollutants)

The New Source Toxics Control rule requires any new or reconstructed major source of hazardous air pollutants (HAPs) for which there are no applicable NESHAP to implement maximum achievable control technology (MACT), determined on a case-by-case basis, when the potential to emit is greater than 10 tons per year of any single HAP. Information on emissions of the 187 hazardous air pollutants (listed in the OAQ Construction Permit Application, Form Y) is set out in the Clean Air Act Amendments of 1990. These pollutants are either carcinogenic or otherwise considered toxic.

The HAP emissions from Duct Burner (being part of HRSG which is electric utility steam generating unit) are exempt from case by case MACT determination pursuant to section 112 (g) as stated in Federal Register Vol. 65 No.102 dated May 25, 2000. The Heat Recovery Steam Generator and the Duct Burner are considered part of the Electric Utility Steam Generating Unit. Therefore, the HAP emissions from the Duct Burner will not be added to the Source wide Hexane emissions to determine applicability of MACT. The New Source Toxic Rule is not applicable because any single HAP emission (excluding emissions from Duct Burner) is less than 10 tons per year and any combination of HAPs emissions (excluding emissions from Duct Burner) are less than 25 tons per year.

The formaldehyde emission from the combustion turbine shall not exceed 0.000158 lb/MMBtu. This will limit the formaldehyde emissions from the entire source below 10 tons per year and make requirements of 326 IAC 2-4.1 not applicable as shown below:

$$\text{Formaldehyde Emissions} = 6 \text{ turbines} \times \frac{0.000158 \text{ lb}}{\text{MMBtu}} \times 1821.8 \frac{\text{MMBtu}}{\text{hour}} = \frac{1.72 \text{ lb}}{\text{hour}}$$

$$= \frac{1.72 \text{ lb}}{\text{hour}} \times \frac{8760 \text{ hour}}{\text{year}} \times \frac{0.0005 \text{ ton}}{\text{lb}}$$

$$= 7.56 \text{ tons/year}$$

Any increase in emissions greater than the threshold specified above from this project must be approved by the Office of Air Quality (OAQ) before such change may occur.

The formaldehyde emission limit above is calculated based on applicant's recommendation of using four time the EPRI study emission factor for the gas turbines. This emission factor calculates out to be 0.000158 lb/MMBtu. The gas turbine emission factor of 0.000158 lb/MMBtu compares well with the emission estimate of 0.00013 lb/MMBtu for similar type turbines. The General Electric International Power Systems in a letter dated August 1, 2001, stated that they tested two (2) GE 7241 FA DLN turbines in combined cycle mode. The testing was conducted for base (100%), mid (75%) and low (50%) loads. They analyzed twenty-eight test measurements. The results showed 66 ppb (parts per billion) concentration for the formaldehyde emissions. This equates to an emission rate of 0.00013 lb/MMbtu.

326 IAC 2-6 (Emission Reporting)

The proposed facility is subject to 326 IAC 2-6 (Emission Reporting) because at least one listed pollutant exceeds its emission threshold level, because the source will emit more than 100 tons per year of VOC, PM10, PM, NO_X and CO. Pursuant to this rule, the owner/operator of this facility must annually submit an emission statement of the facility. The annual statement must be received by July 1 of each year and must contain the minimum requirements as specified in 326 IAC 2-6-4.

326 IAC 3-5 (Continuous Monitoring of Emissions)

The proposed facility is subject to 326 IAC 3-5 (Continuous Monitoring of Emissions) because the unit is a fossil fuel-fired steam generator with a heat input capacity greater than 100 MMBtu per hour as defined by 326 IAC 3-5-1(b)(2).

(a) Pursuant to 326 IAC 3-5-1(c)(2)(A)(i), and opacity monitor is not required because only gaseous fuel is combusted. The only fuel combusted in the combustion turbines and duct burners at this source is natural gas.

(b) Pursuant to 326 IAC 3-5-1(c)(2)(B), an SO_2 continuous emission monitor (CEM) is not required because each steam generating unit is not equipped with an SO_2 control and 40 CFR 60 Subpart Db does not require an SO_2 monitor because only natural gas is combusted.

(c) Pursuant to 326 IAC 3-5-1(d)(1), the owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 326 IAC 2-2 shall be required to install a continuous emission monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5.

For NO_X and CO, the Permittee shall install, calibrate, certify, operate and maintain a continuous monitoring system for stacks designated as GT-1 through GT-6 in accordance with 326 IAC 3-5-2 through 326 IAC 3-5-7.

(1) The continuous emission monitoring system (CEMS) shall measure NO_X and CO emissions rates in pounds per hour and parts per million (ppmvd) at 15% O_2. The use of CEMS to measure and record the NO_X and CO hourly limits is sufficient to demonstrate compliance with the limitations established in the BACT analysis. To demonstrate compliance with the NO_X limit, the source shall take an average of the parts per million (ppm) at 15% O_2 over a three (3) block. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) 15% O_2 over a twenty four (24) hour period. The source shall maintain records of the parts per million and the pounds per hour.

(2) The Permittee shall submit to IDEM, OAQ, within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

(3) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7. The source shall also be required to maintain records of the amount of natural gas combusted per turbine on a monthly basis and the heat input capacity.

Compliance with this condition shall determine continuous compliance with the NO_X, CO and SO_2 emission limits established under the PSD BACT (326 IAC 2-2).

326 IAC 5-1-2 (Opacity Limitations)

Pursuant to 326 IAC 5-1-2 (Opacity Limitations) except as provided in 326 IAC 5-1-3 (Temporary Exemptions), the opacity shall meet the following:

(a) Opacity shall not exceed an average of 40% any one (1) six (6) minute averaging period.

(b) Opacity shall not exceed 60% for more than a cumulative total of 15 minutes (60 readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute non-overlapping integrated averages for a continuous opacity monitor) in a 6-hour period.

326 IAC 6-2 (Particulate Emissions Limitations for Sources of Indirect Heating)

The proposed electric generation plant is not subject to the requirements of 326 IAC 6-2 because the combustion turbines are not utilized for indirect heating.

326 IAC 6-4 (Fugitive Dust Emission Limitations)

The proposed source is subject to the requirements of 326 IAC 6-4 because this rule applies to all sources of fugitive dust. Pursuant to the applicability requirements, “fugitive dust “ means the generation of particulate matter to the extent that some portion of the material escapes beyond the property line of boundaries of the property, right-of-way, or easement on which the source is located. The source shall be considered in violation of this rule if any of the criteria presented in 326 IAC 6-4-2 are violated.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)

The proposed source is subject to the requirements of 326 IAC 6-5 because the source is required to obtain a permit pursuant to 326 IAC 2. However, the OAQ shall exempt the source from the fugitive control plan pursuant to 326 IAC 6-5-3(b) because the proposed plant will not have material delivery of handling systems that would generate fugitive emissions and all of the roads and parking areas located at the proposed facility will be paved.

326 IAC 7-1 (Sulfur Dioxide Emission Limitations)

The proposed power plant is subject to the requirements of 326 IAC 7-1 because the plant is a fuel combustion facility and the SO_2 potential to emit is greater than 25 tons per year. Pursuant to 326 IAC 7-1.1-2, there are no specific emission limitations for the combustion of natural gas. Pursuant to 326 IAC 7-2-1, the Permittee shall submit natural gas reports of the calendar month average sulfur content, heat content, fuel consumption and sulfur dioxide emission rate in pounds per million Btu, upon request of OAQ.

326 IAC 8-1-6 (New facilities; general reduction requirements)

Pursuant to 326 IAC 8-1-6 (New facilities; general reduction requirements), the requirements of BACT shall apply to each turbine because the potential to emit of VOC is greater than or equal to 25 tons per year per unit. Pursuant to 326 IAC 8-1-6, the source's BACT requirements under 326 IAC 2-2 (PSD) are equivalent to BACT under this rule.

326 IAC 8 (Volatile organic Compound Requirements)

The proposed power plant is not subject to any other state VOC requirements because there is not a source specific RACT for the proposed operation.

326 IAC 9 (Carbon Monoxide Emission Limits)

Pursuant to 326 IAC 9 (Carbon Monoxide Emission Limits), the source is subject to this rule because it is a stationary source that emits CO emissions and commenced operation after March 21, 1972. Under this rule, there is not a specific emission limit because the source is not an operation listed under 326 IAC 9-1-2.

326 IAC 10 (Nitrogen Oxides)

This power plant is an "Electricity Generating Unit" because it will have generators greater than 25 MW, electricity production capacity for sale and will commence operation after January 1, 1999. Therefore, this source is subject to the requirements of rule 326 IAC 10-4-1 that establishes a NOx trading program for these units.

Conclusion

The construction of this combined-cycle power plant will be subject to the conditions of the attached proposed **Construction Permit No. CP-167-12760-00125.**

Appendix A: Emissions Calculations
Summary of Emissions

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **25-Apr-02**

Potential to Emit Uncontrolled/Unlimited

Pollutant	CC Turbine (tons/year)	CC Turbine SU/SD (tons/year)	Cooling Tower (tons/year)	Auxiliary Boiler	Black Start Generator	Emergency Generator	Fire Pump	Total (tons/year)
NOx	5216.61	307.188	-	8.58	2183.34	181.95	49.97	7947.64
CO	2226.74	4239.83	-	14.37	470.48	39.21	10.77	7001.38
VOC	378.29		-	0.95	177.07	14.76	4.05	575.11
SO2	347.42		-	0.10	144.38	12.03	12.03	515.97
H2SO4 Mist	212.87		-					212.87
PM/PM10	467.41		4.78	1.31	154.95	12.91	3.546	644.90
Formaldehyde*	8.62		-					8.62
Combined HAP*	22.28		-					22.28

Limited or Controlled PTE

Pollutant	CC Turbine (tons/year)	CC Turbine SU/SD (tons/year)	Cooling Tower (tons/year)	Auxiliary Boiler	Black Start Generator	Emergency Generator	Fire Pump	Total (tons/year)
NOx	521.66	307.188	-	0.98	124.62	5.19	1.43	961.07
CO	822.77	4239.83	-	1.64	26.85	1.12	0.31	5092.52
VOC	378.29		-	0.11	10.11	0.42	0.12	389.04
SO2	347.42		-	0.01	8.24	0.34	0.34	356.36
H2SO4 Mist	212.87		-					212.87
PM/PM10	467.41		4.78	0.15	8.84	0.37	0.101	481.65
Formaldehyde*	8.62		-					8.62
Combined HAP*	22.28		-					22.28

*The HAP emissions from Duct Burner are exempt from case by case MACT determination pursuant to section 112 (g) as stated in Federal Register Vol. 65 No.102 dated May 25, 2000.

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **April 25, 2002**

Combined Cycle - Mitsubishi 501 F Combustion Turbines and Duct Burners
Combustion Turbine Potential to Emit Calculations - Before Controls or Federally Enforceable Limits

Combustion Turbine Heat input @ 59 F	**1821.80**	MMBtu/hr	@ HHV	Number of Turbines	**6**
Power Augmentation and Combustion Turbine Heat input @ 74 F	**2112.00**	MMBtu/hr	@ HHV		
Duct Burner Heat input	**550**	MMBtu/hr	@ HHV	Number of Duct Burners	**6**

	Normal Operation	Startup/Shutdown
Turbine Operation (hrs/yr)	**6518**	**742**
Duct Burner Operation (hrs/yr)	**6518**	
Turbine and Duct Burner operation with Power Augmentation (hrs/yr) at 74 F	**1500**	

Combined Combustion Turbine and Duct Burner Emissions					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	2371.80 MMBtu/hr	0.0906 lb/MMBtu	215.00	700.69 tons/yr	4204.11 tons/yr
CO	2371.80 MMBtu/hr	0.0198 lb/MMBtu	47.00	153.17 tons/yr	919.04 tons/yr
VOC	2371.80 MMBtu/hr	0.0051 lb/MMBtu	12.10	43.92 tons/yr	263.54 tons/yr
SO_2	2371.80 MMBtu/hr	0.0055 lb/MMBtu	13.10	47.55 tons/yr	285.32 tons/yr
H2SO4 Mist*	2371.80 MMBtu/hr	0.0034 lb/MMBtu	8.10	29.40 tons/yr	176.42 tons/yr
PM_{10}**	2371.80 MMBtu/hr	0.0075 lb/MMBtu	17.70	64.25 tons/yr	385.51 tons/yr

Power Augmentation for Combustion Turbine and Duct Buner Emissions					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	2662.00 MMBtu/hr	0.0845 lb/MMBtu	225.00	168.75 tons/yr	1012.50 tons/yr
CO	2662.00 MMBtu/hr	0.1092 lb/MMBtu	290.60	217.95 tons/yr	1307.70 tons/yr
VOC	2662.00 MMBtu/hr	0.0096 lb/MMBtu	25.50	19.13 tons/yr	114.75 tons/yr
SO_2	2662.00 MMBtu/hr	0.0052 lb/MMBtu	13.80	10.35 tons/yr	62.10 tons/yr
H2SO4 Mist*	2662.00 MMBtu/hr	0.0030 lb/MMBtu	8.10	6.08 tons/yr	36.45 tons/yr
PM10**	2662.00 MMBtu/hr	0.0068 lb/MMBtu	18.20	13.65 tons/yr	81.90 tons/yr

Total uncontrolled Potential Emissions from Combustion Turbines and Duct Burners	
Pollutant	Total PTE
NO_X	5216.61 tons/yr
CO	2226.74 tons/yr
VOC	378.29 tons/yr
SO_2	347.42 tons/yr
H2SO4 Mist*	212.87 tons/yr
PM10**	467.41 tons/yr

Combustion turbine emission factors are vendor provide data
Calculations are based on 8760-SU/SD hours per year of operation (Normal Opeartion + Startup/Shutdown = 8760 hrs/yr)
*due to lack of more accurate emission factors, the H2SO4 mist emission factor is assumed same with or without power augmentation

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: Tenaska Indiana Partners, LP
Address City IN Zip: County Road 625 East, Otwell, IN 47564
CP: 125-12760
Plt ID: 125-00039
Reviewer: GS
Date: April 25, 2002

Combined Cycle - Mitsubishi 501 F Combustion Turbines and Duct Burners
Combustion Turbine Potential to Emit Calculation - After Control or Federally Enforceable Limits

Combined Combustion Turbine and Duct Burner Emissions					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	2371.8 MMBtu/hr	0.0091 lb/MMBtu	21.50	70.07 tons/yr	420.41 tons/yr
CO	2371.8 MMBtu/hr	0.0119 lb/MMBtu	28.20	91.90 tons/yr	551.42 tons/yr
VOC	2371.8 MMBtu/hr	0.0051 lb/MMBtu	12.10	43.92 tons/yr	263.54 tons/yr
SO_2	2371.8 MMBtu/hr	0.0055 lb/MMBtu	13.10	47.55 tons/yr	285.32 tons/yr
H2SO4 Mist*	2371.8 MMBtu/hr	0.0034 lb/MMBtu	8.10	29.40 tons/yr	176.42 tons/yr
PM_{10}**	2371.8 MMBtu/hr	0.0075 lb/MMBtu	17.70	64.25 tons/yr	385.51 tons/yr

Power Augmentation for Combustion Turbine and Duct Buner Emissions					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	2662.00 MMBtu/hr	0.0085 lb/MMBtu	22.50	16.88 tons/yr	101.25 tons/yr
CO	2662.00 MMBtu/hr	0.0227 lb/MMBtu	60.30	45.23 tons/yr	271.35 tons/yr
VOC	2662.00 MMBtu/hr	0.0096 lb/MMBtu	25.50	19.13 tons/yr	114.75 tons/yr
SO_2	2662.00 MMBtu/hr	0.0052 lb/MMBtu	13.80	10.35 tons/yr	62.10 tons/yr
H2SO4 Mist*	2662.00 MMBtu/hr	0.0030 lb/MMBtu	8.10	6.08 tons/yr	36.45 tons/yr
PM10**	2662.00 MMBtu/hr	0.0068 lb/MMBtu	18.20	13.65 tons/yr	81.90 tons/yr

Total uncontrolled Potential Emissions from Combustion Turbines and Duct Burners	
Pollutant	Total PTE
NO_X	521.66 tons/yr
CO	822.77 tons/yr
VOC	378.29 tons/yr
SO_2	347.42 tons/yr
H2SO4 Mist*	212.87 tons/yr
PM10**	467.41 tons/yr

Note - All emission rates are based on vendor provided data. The Permittee will be required to Stack test for all criteria pollutants to show that the actual emission rates are equal to or less than shown above.

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **April 25, 2002**

Startup/Shutdown Emissions

Combined Cycle Operation - Mitsubishi 501 F

	Hot	Warm	Cold
Estimated max startups per year	**70**	**70**	**70**
Startup duration (hours)	**1.28**	**2.37**	**4.95**
Total startup hours in a year			**602**
Estimated max shutdowns per year	**70**	**70**	**70**
Shutdown duration (hours)	**0.67**	**0.67**	**0.67**
Total shutdown hours in a year			**140**

Emissions from Combined Cycle Opeartion						
Pollutant	Type	Duration (hours)	Startup Emission Rate per turbine (lb/Startup)	Shutdown Emission Rate per turbine (lb/shutdown)	Emission Rate/turbine (tons/yr)	Total Emission Rate based startup of all turbine (tons/yr)
NO_X	Hot	1.28	182.0	49.6	8.11	48.64
	Warm	2.37	354.0	49.6	14.13	84.76
	Cold	4.95	778.0	49.6	28.97	173.80
Total NOx per year					51.2	307.19
CO	Hot	1.28	1294.0	712.0	45.31	271.88
	Warm	2.37	4625.0	712.0	186.80	1120.77
	Cold	4.95	12846.0	712.0	474.53	2847.18
Total CO per year					706.64	4239.83

*Emission rate/Turbine (tpy) includes both the startup and shutdown
Emission rates provided by the vendor

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **April 25, 2002**

Combustion Turbines and Duct Burners Potential to Emit Calculations for HAPs

	Duct Burner				Combustion Turbine				Total HAPs CT + DB
HAPs	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr)	ton/yr @8760 hrs/yr (x6)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr)	ton/yr @ 8760 hrs/yr (x6)	tons/yr
Benzene	2.06E-06	1.13E-03	4.96E-03	2.98E-02	1.20E-05	1.35E-01	5.90E-01	3.54E+00	3.57E+00
Dichlorobenzene	1.18E-06	6.47E-04	2.83E-03	1.70E-02				0.00E+00	1.70E-02
Formaldehyde*	7.35E-05	4.04E-02	1.77E-01	1.06E+00	1.58E-04	2.88E-01	1.26E+00	7.56E+00	8.62E+00
Xylenes					6.40E-05	1.35E-01	5.92E-01	3.55E+00	3.55E+00
Hexane**	1.48E-04	8.14E-02	3.57E-01	2.14E+00					2.14E+00
Ethylbenzene					3.20E-05	6.76E-02	2.96E-01	1.78E+00	1.78E+00
1,3 Butadiene					4.30E-07	9.08E-04	3.98E-03	2.39E-02	2.39E-02
Napthalene	5.98E-07	3.29E-04	1.44E-03	8.64E-03	1.30E-06	2.75E-03	1.20E-02	7.22E-02	8.08E-02
Toluene	3.33E-06	1.83E-03	8.03E-03	4.82E-02	1.30E-04	4.89E-02	2.14E-01	1.29E+00	1.33E+00
PAH					2.20E-06	4.65E-03	2.04E-02	1.22E-01	1.22E-01
POM	8.65E-08	4.76E-05	2.08E-04	1.25E-03					1.25E-03
Acetaldehyde					4.00E-05	3.67E-02	1.61E-01	9.65E-01	9.65E-01
Arsenic	1.96E-07	1.08E-04	4.72E-04	2.83E-03					2.83E-03
Beryllium	1.18E-08	6.47E-06	2.83E-05	1.70E-04					1.70E-04
Cadmium	1.08E-06	5.93E-04	2.60E-03	1.56E-02					1.56E-02
Chromium	1.37E-06	7.55E-04	3.31E-03	1.98E-02					1.98E-02
Cobalt	8.24E-08	4.53E-05	1.98E-04	1.19E-03					1.19E-03
Manganese	3.73E-07	2.05E-04	8.97E-04	5.38E-03					5.38E-03
Mercury	2.55E-07	1.40E-04	6.14E-04	3.68E-03					3.68E-03
Nickel	2.06E-06	1.13E-03	4.96E-03	2.98E-02					2.98E-02
Selenium	2.35E-08	1.29E-05	5.67E-05	3.40E-04					3.40E-04
single HAP			0.36	2.14			1.26	7.56	8.62
combined HAP			0.56	3.39			3.15	18.89	22.28

HAPs emission factors for the turbines are from AP-42 Table 3.1-3

HAPs emission factors for the duct burners are from AP-42 Table 1.4-3

*based on applicant's recommendation, the formaldehyde emission factor for gas turbine is calculated by multiplying EPRI study factor by 4.0. This is comparable to stack test for similar size turbine presented by the applicant as part of the application. For Duct Burners it is standard AP 42 emission factor

Appendix A: Emissions Calculations
Auxillary Boiler Emissions
MM BTU/HR <100
Small Industrial Boiler

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **25-Apr-02**

Natural Gas Utility Boiler Calculation

Auxiliary Boiler Heat Input Rate: 40 MMBtu/hr
Number of Boilers: 1

Boiler Operation (hrs/yr): 1000
Annual gas usage (MMSCF): 38.1

Auxiliary Boiler									
Pollutant	Heat Input		Emission Factor		lb/hr	Boiler PTE		PTE after Control or Enforcable Limits	
NO_X	40	MMBtu/hr	4.90E-02	lb/MMBtu	1.960	8.585	ton/yr	0.980	ton/yr
CO	40	MMBtu/hr	8.20E-02	lb/MMBtu	3.280	14.366	ton/yr	1.640	ton/yr
VOC	40	MMBtu/hr	5.40E-03	lb/MMBtu	0.216	0.946	ton/yr	0.108	ton/yr
SO_2	40	MMBtu/hr	5.88E-04	lb/MMBtu	0.024	0.103	ton/yr	0.012	ton/yr
PM_{10}	40	MMBtu/hr	7.50E-03	lb/MMBtu	0.300	1.314	ton/yr	0.150	ton/yr

*Emission factors are from AP-42 Table 1.4-2 utilizing Low NOx Burners
*Emission factors are based on a heating value of natural gas of 1050 Btu/scf

Pollutant	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE Before Control (tpy)	PTE After Control or Enforceable Limit (tpy)
Benzene	2.10E-03	2.00E-06	8.00E-05	3.50E-04	4.00E-05
Diclorobenzene	1.20E-03	1.14E-06	4.57E-05	2.00E-04	2.29E-05
Formaldehyde	7.50E-02	7.14E-05	2.86E-03	1.25E-02	1.43E-03
Hexane	1.80E+00	1.71E-03	6.86E-02	3.00E-01	3.43E-02
Napthalene	6.10E-04	5.81E-07	2.32E-05	1.02E-04	1.16E-05
Toluene	3.40E-03	3.24E-06	1.30E-04	5.67E-04	6.48E-05
POM	8.87E-05	8.45E-08	3.38E-06	1.48E-05	1.69E-06
Arsenic	2.00E-04	1.90E-07	7.62E-06	3.34E-05	3.81E-06
Beryllium	1.20E-05	1.14E-08	4.57E-07	2.00E-06	2.29E-07
Cadmium	1.10E-03	1.05E-06	4.19E-05	1.84E-04	2.10E-05
Chromium	1.40E-03	1.33E-06	5.33E-05	2.34E-04	2.67E-05
Cobalt	8.40E-05	8.00E-08	3.20E-06	1.40E-05	1.60E-06
Manganese	3.80E-04	3.62E-07	1.45E-05	6.34E-05	7.24E-06
Mercury	2.60E-04	2.48E-07	9.90E-06	4.34E-05	4.95E-06
Nickel	2.10E-03	2.00E-06	8.00E-05	3.50E-04	4.00E-05
Selenium	2.40E-05	2.29E-08	9.14E-07	4.00E-06	4.57E-07
		Single HAP		**3.00E-01**	**3.43E-02**
		Combined HAP		**3.15E-01**	**3.60E-02**

*HAPs emission factors based on AP-42 1.4-3

Appendix A: Emissions Calculations
Cooling Tower Emissions

Company Name:	**Tenaska Indiana Partners, LP**
Address City IN Zip:	**County Road 625 East, Otwell, IN 47564**
CP:	**125-12760**
Plt ID:	**125-00039**
Reviewer:	**GS**
Date:	**April 25, 2002**

Cooling Tower Emissions

	Value	Unit	Calculation
Flow of Water at 100% Load	278480	gpm	vendor information
Cooling Water Flowrate	139351392	lb/hr	Flowrate (gal/min) * 8.34 lb/gal * 60 min/hr
Total Disolved Solids (TDS)	1566	ppm	vendor information
Cooling Water TDS Fraction	0.001566	lb TDS/lb	TDS/10^6 lb/ppm
Drift Loses (% of cooling water)	0.0005	%	vendor information
Liquid Drift Losses	696.757	lb/hr	Cooling water flow rate lb/hr * 0.001/100
Solids Drift Losses	1.091	lb/hr	Liquid Drift Losses * TDS Fraction lb TDS/lb
PM_{10}/TSD Emission	4.779	ton/yr	

Appendix A: Emissions Calculations
Black-Start Generator

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **April 25, 2002**

Number of Generators 6

Heat Input Capacity Horsepower (hp)	Potential Throughput hp-hr/yr	Potential Throughput at 500 Limited hour per Generator per year hp-hr/yr
2680	23476800	1340000

	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.00205	0.031	0.0025141	0.00668
Potential Emission in tons/yr	154.95	154.95	144.38	2183.34	177.07	470.48
Limited Potential Emission in tons/yr	8.84	8.84	8.24	124.62	10.11	26.85

Fuel Limit per Generator = 94733 gallons of diesel

Methodology

Potential Througput (hp-hr/yr) = hp * 8760 hr/yr
Use a conversion factor of 7,000 Btu per hp-hr to convert from horsepower to Btu/hr, unless the source gives you a source-specific brake-specific fuel consumption. (AP-42, Footnote a, Table 3.3-1)
Emission Factors are from AP42 (Supplement B 10/96), Table 3.3-2
Emission (tons/yr) = [Potential Throughput (hp-/hr/yr) x Emission Factor (lb/hp-hr)] / (2,000 lb/ton)

Appendix A: Emissions Calculations
Emergency Generator

Company Name: **Tenaska Indiana Partners, LP**
Address City IN Zip: **County Road 625 East, Otwell, IN 47564**
CP: **125-12760**
Plt ID: **125-00039**
Reviewer: **GS**
Date: **April 25, 2002**

Heat Input Capacity Horsepower (hp)	Potential Throughput hp-hr/yr	Potential Throughput at 250 Limited hour per year hp-hr/yr
1340	11738400	335000

	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.00205	0.031	0.0025141	0.00668
Potential Emission in tons/yr	12.91	12.91	12.03	181.95	14.76	39.21
Limited Potential Emission in tons/yr	0.37	0.37	0.34	5.19	0.42	1.12

Fuel Limit per Generator = 23683 gallons of diesel

Methodology

Potential Througput (hp-hr/yr) = hp * 8760 hr/yr
Use a conversion factor of 7,000 Btu per hp-hr to convert from horsepower to Btu/hr, unless the source gives you a source-specific brake-specific fuel consumption. (AP-42, Footnote a, Table 3.3-1)
Emission Factors are from AP42 (Supplement B 10/96), Table 3.3-2
Emission (tons/yr) = [Potential Throughput (hp-/hr/yr) x Emission Factor (lb/hp-hr)] / (2,000 lb/ton)

Appendix A: Emissions Calculations
Emergency Generator

Company Name:	**Tenaska Indiana Partners, LP**
Address City IN Zip:	**County Road 625 East, Otwell, IN 47564**
CP:	**125-12760**
Plt ID:	**125-00039**
Reviewer:	**GS**
Date:	**April 25, 2002**

Heat Input Capacity Horsepower (hp)	Potential Throughput hp-hr/yr	Potential Throughput at 250 Limited hour per year hp-hr/yr
368	3223680	92000

	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.00205	0.031	0.0025141	0.00668
Potential Emission in tons/yr	3.55	3.55	3.30	49.97	4.05	10.77
Limited Potential Emission in tons/yr	0.10	0.10	0.09	1.43	0.12	0.31

Fuel Limit per Generator = 6504 gallons of diesel

Methodology

Potential Througput (hp-hr/yr) = hp * 8760 hr/yr
Use a conversion factor of 7,000 Btu per hp-hr to convert from horsepower to Btu/hr, unless the source gives you a source-specific brake-specific fuel consumption. (AP-42, Footnote a, Table 3.3-1)
Emission Factors are from AP42 (Supplement B 10/96), Table 3.3-2
Emission (tons/yr) = [Potential Throughput (hp-/hr/yr) x Emission Factor (lb/hp-hr)] / (2,000 lb/ton)

Appendix B- Air Quality Analysis

Source Background and Description

Source Name:	Tenaska Indiana Partners, L.P.
Source Location:	County Road 625 East, Otwell, IN 47564
County:	Pike
Construction Permit No.:	CP-125-12760-00039
SIC Code:	4911
Modeler:	Michael Mosier

Introduction

Tenaska Indiana Partners, L.P. (Tenaska) has applied for a Prevention of Significant Deterioration (PSD) Permit to construct a natural-gas-fired combined-cycle electric generating facility near Petersburg in Pike County, Indiana. The proposed site will be located approximately 6 miles southeast of Petersburg at Universal Transverse Mercator (UTM) coordinates 485761 East and 4257955 North. The proposed electric generation facility will have a plant output rate of approximately 1800 megawatts (MW). The plant will incorporate six natural-gas-fired combustion turbines (CTs), six natural-gas-fired sets of duct burners (DBs), six heat recovery steam generators (HRSGs), one natural-gas-fired auxiliary boiler, six diesel-oil-fired blackstart generators, one diesel-oil-fired emergency generator, one diesel-driven firewater pump, two cooling towers, and two steam turbines (STs). Pike County is designated attainment for all criteria pollutants. All air quality modeling and analysis treats the proposed electric generation facility as a new major source.

AirPermits.com prepared the permit application for Tenaska. The Office of Air Quality (OAQ) received the permit application on October 2000. Modeling revisions to the application were received on December 2000 and June 2001. This document provides the OAQ review of the modeling section of the permit application.

Air Quality Impact Objectives

The purpose of the air quality impact analysis in the permit application is to accomplish the following objectives. Each objective is individually addressed in this document in each section outlined below.

A. Establish which pollutants require an air quality analysis based on PSD significant emission rates.

B. Provide analyses of actual stack heights with respect to Good Engineering Practice (GEP), the meteorological data used a description of the model used in the analysis, and the receptor grid utilized for the analyses.

C. Determine the background (existing) air quality levels, the significant impact area (if one is established) the area of potential impact of the source's emissions and the need for more refined (cumulative) modeling.

D. Demonstrate that the source will not cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS) or PSD increment if the applicant exceeds significant impact levels.

E. Perform an analysis of any air toxic compound with a health risk factor on the general population.

F. Perform a qualitative analysis of the source's impact on general growth, soils, vegetation and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is Kentucky's Mammoth Cave National Park, which is more than 100 kilometers from the proposed site in Pike County, Indiana.

G. Summarize the Air Quality Analysis

Analysis Summary

The air quality impact analysis determined that no refined modeling would be required since pollutant concentrations did not exceed significant impact levels. The Reactive Plume Model–IV (RPM-IV) results showed no significant impact to ozone formation. Hazardous Air Pollutant (HAP) concentrations were all below .5% of the Permissible Exposure Limit (PEL). Based on these modeling results, the proposed Tenaska Plant will not have a significant impact to air quality.

Section A

Pollutants Analyzed for Air Quality Impact

The PSD requirements, 326 IAC 2-2, apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted in significant amounts by a major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1. Particulate Matter less than 10 microns (PM_{10}), Sulfur Dioxide (SO_2), Nitrogen Dioxide (NO_2), Volatile Organic Compounds (VOC)(an Ozone (O_3) precursor), and Carbon Monoxide (CO), are the pollutants that will be emitted from the electric generation facility. Therefore, an air quality analysis is required for these pollutants, which exceeded their significant emission rates as shown in Table 1:

TABLE 1
Significant Emission Rates for PSD

POLLUTANT	SOURCE EMISSION RATE[1] (Facility Totals)	SIGNIFICANT EMISSION RATE	PRELIMINARY AQ ANALYSIS REQUIRED
	(tons/year)	(tons/year)	
PM_{10}	482	15.0	Yes
NO_2	654	40.0	Yes
VOCs (O_3)	389	40.0	Yes
CO	1170	100.0	Yes
SO_2	356	40	Yes
Sulfuric Acid Mist	213	7	N/A[2]

[1] PTE emissions after controls based on 8760 hours of operation excluding startup/shutdown emissions.
[2] No AQ analysis is required under the PSD regulations.

Section B

Stack Height Compliance with Good Engineering Practice (GEP)

Stacks should comply with GEP requirements established in 326 IAC 1-7-1. If stacks are lower than GEP, the modeled concentrations may be significantly higher due to aerodynamic downwash. Stacks taller than 65 meters (213 feet) are limited to GEP, the stack height for establishing emission limitations. The GEP stack height takes into account the distance and dimensions of nearby structures, which would affect the downwind wake of the stack. The downwind wake is considered to extend five times the lesser of the structure's height or width.

A GEP stack height is determined for each nearby structure by the following formula:

$$Hg = H + 1.5L$$

Where: Hg is the GEP stack height
H is the structure height
L is the structure's lesser dimension (height or width)

Since the stack heights of the proposed facility were below GEP stack height the effect of aerodynamic downwash was accounted for in the air quality analysis for the proposed electric generation facility.

Meteorological Data

The meteorological data used in the Industrial Source Complex Short Term (ISCST3) model consisted of years 1990 through 1994 surface data from the Evansville Airport Weather Service station merged with the mixing heights from Peoria, Illinois Airport National Weather Service station. The meteorological data was preprocessed into ISCST3 ready format using U.S.EPA's PCRAMMET and provided to AirPermits.com by the Indiana Department of Environmental Management (IDEM).

Model Description

AirPermits.com and OAQ independently used the ISCST3 model, version 00101 to determine maximum off-property concentrations or impacts for each pollutant. All regulatory default options were utilized in the U.S. EPA approved model, as listed in the 40 Code of Federal Register Part 51, Appendix W "Guideline on Air Quality Models". The Auer Land Use Classification Scheme was used to determine the land use in the area. The area is considered primarily rural; therefore, a rural classification was used.

Receptor Grid

OAQ modeling utilized the same receptor grids generated by AirPermits.com, which extended around the property line in 100-meter increments. A large grid consisting of receptors spaced at 364-meter increments in the east-west direction and 462 meter increments in the north-south direction out to a distance of 10,000 meters. A refined grid of receptors spaced at approximately 73 meters by 92 meters at a distance of 500 meters.

<u>Section C</u>

Significant Impact Level/Significant Impact Area (SIA) and Background Air Quality Levels

AirPermits.com and Tenaska determined the worst case operating scenarios for modeling. AirPermits.com performed a significant impact area analysis for 29 different scenarios for the combustion turbines and duct burners. Scenarios modeled were based on different operating load conditions, stack temperatures, and flow rate conditions.

AirPermits.com and OAQ performed an air quality modeling analysis to determine if the source exceeded the significant impact levels (concentrations). If the source's concentrations exceed these levels, IDEM and USEPA guidance requires further air quality analysis. Refined modeling for PM_{10}, SO_2, NO_2 and CO was not required because the results any of the analyses did not exceed significant impact levels. Sulfuric acid mist has no significant impact level. PSD regulations do not require modeling for sulfuric acid since there is no significant impact level, NAAQS, or PSD increment. Significant impact levels are defined by the time periods presented in the following Table as well as all maximum modeled concentrations from the worst case operating scenarios. Since none of the pollutants exceed the significant impact level, a significant impact area does not exist.

Table 3
Significant Impact Analysis

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS (ug/m^3)	SIGNIFICANT IMPACT LEVEL (ug/m^3)	REFINED AQ ANALYSIS REQUIRED
PM_{10}	24 Hour	4.9	5	No
PM_{10}	Annual	0.219	1	No
NO_2	Annual	0.95[1]	1	No
CO	1 Hour	590.52	2000	No
CO	8 Hour	173.8	500	No
SO_2	3 Hour	22.4	25	No
SO_2	24 Hour	3.07	5	No
SO_2	Annual	.1241	1	No
Sulfuric Acid Mist	8 hour	3.7	N/A	No

[1]U.S. EPA NO2/NOx ratio was used to determine NO2 impacts based on the NOx emission rates. 40 CFR 51, Appendix W – Guideline on Air Quality Models.

An emission start-up modeling analysis was also performed to determine if start-up emissions would exceed short-term NAAQS averaging times. Start-up emissions can be higher than normal operating emissions for short periods of time. The two averaging times of concern are the CO 1 hour and SO_2 3 hour periods. SO_2 was not modeled since the emissions are lower than normal operations. The results of the analysis are shown below in Table 4.

Table 4
Emission Start-Up Modeling Analysis

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS (ug/m^3)	NAAQS (ug/m^3)	Exceeded NAAQS
CO	1 Hour	7155	40000	No

The results of the emission start-up analysis show no violation of the short-term averaging periods for CO.

O_3 does not have a significant impact level to determine whether modeling is needed. The significant emission rate for VOCs and NOx is used to determine the need for O_3 modeling. OAQ policy is to perform an air quality screening analysis for O_3 since the source's NOx emissions exceeded the significant emission rate. The RPM-IV modeling was used to calculate the O_3 concentrations as a result of NOx and VOC emissions from the source. Screening results from the ozone modeling are described in more detail in Section D of this document.

Section D

RPM-IV Inputs for Ambient and Plume-Injected Modes for the O_3 (VOC and NOx) NAAQS Analysis

The RPM-IV model is used as a screening tool to predict O_3 impact from the facility. It is a photochemical plume-segment model that simulates a photochemical plume by representing the plume as a series of cells across the horizon of the plume. RPM-IV consists of a Lagrangian model that follows a parcel of air pollutants as it travels downwind from a point source. Simulation of ambient air and resulting chemical transformations with a plume occur within the model to represent conditions in the atmosphere.

The RPM-IV model was run in two modes; the first mode determined ambient conditions for a day when high O_3 concentrations were recorded. The second mode injects the VOC and NOx plume from the point source into the ambient mode. The second mode will thus contain both ambient and plume injected concentrations. The concentration from the second mode is subtracted from the first mode at specified downwind distances and the difference between the two modes is the impact from the source. Source impact, which is less than 3 parts per billion (ppb) is not significant and is not subject to further refined modeling. There are five main sections, which make up a RPM-IV input file. These sections and a short description of each are as follows:

1) INPUT - Define plume type, duration, location, output interval and plume definition and program flow variables.
2) CHEMIN - Define chemical mechanism RPM-IV reaction species, product species, reaction rates, and temperature.
3) SOURCES - Data for emission injections, which include stack parameters and source emission rates.
4) METIN - Meteorological and ambient species concentrations, plume expansion rates and photolysis reaction rates.
5) RESULT - Parameters, which control the display of RPM-IV simulation.

The plume-injected mode models the ambient conditions as well as VOCs and NOx emissions from the source. Complete stack information as well as each specie's emission rate must be input into the model. VOC and NOx specie concentrations from the source are listed in Table 5.

TABLE 5
Source Species emissions (g/sec)

CHEMICAL SPECIES/CATEGORY	EMISSION RATES (g/s)
Formaldehyde	2.8
Paraffins	.122
NO2	29.40
NO	1.5

The most current available Indiana meteorological data used is June 1994. The meteorological conditions chosen are conducive to ozone formation. Since RPM-IV is used as screening model, the meteorological conditions are not specific to a locality but are more regional in nature. These meteorological conditions can occur at any given location in the state.

It is assumed that all VOCs and NOx emissions come from the one stack, since RPM-IV is used as a screening tool. The OAQ had to adjust the initial concentrations to obtain a 120 ppb ambient ozone concentration. The RPM-IV modeling results are shown in Table 6.

TABLE 6
Tenaska NAAQS Analysis for Ozone

SIMULATION TIME	DISTANCE	AMBIENT MODE SIMULATION	PLUME INJECTED SIMULATION	DIFFERENCE PLUME – AMBIENT
(minutes)	(meters)	(ppb)	(ppb)	(ppb)
0	100	28	28	0
60	7120	44.5	44.9	.5
120	13100	61.6	61.7	.1
180	19700	78.1	78.0	-.1
240	26700	91.7	91.4	-.3
300	32600	103	103	0
360	40200	111	111	0
420	51600	116	115	-1
480	63600	118	116	-2
540	81100	118	115	-3
600	101000	118	115	-3
660	115000	118	115	-3
720	126000	118	115	-3

All plume-injected modes minus ambient are negative or slightly positive for every time period and every distance. The proposed electric generation facility's positive impact is less than 3ppb and will not have a significant contribution to the maintenance of the NAAQS. Since there are no significant modeled contributions, further modeling for O_3 impacts from this source is not required. Impacts of less than 3 ppb are thought to be insignificant because it falls well within the range of the minimum detectable amount for a monitor.

Part E

Hazardous Air Toxics Analysis and Results

The OAQ presently requests data concerning the emission of 189 HAPs listed in the 1990 Clean Air Act Amendments (CAAA) which are either carcinogenic or otherwise considered toxic and may be used by industries in the State of Indiana. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Quality's construction permit application Form Y. Any HAP emissions are subject to toxic modeling analysis.

As a precautionary measure, AirPermits.com and OAQ modeled the toxics using ISCST3 and compared the maximum-modeled 8-hour concentration with the 0.5% PEL value. The maximum-modeled concentrations are shown in Table 7.

Table 7
Air Toxic Analysis

Toxic Compound	tons/year	Conc. (ug/m3)	0.5% of PEL (ug/m3)
Acetaldehyde	**.96**	**.092**	**1800**
Acrolein	.36	.016	1.25
Benzene	3.57	.228	16
1,3-Butadiene	.024	.004	11000
Ethylbenzene	.32	.006	2175
Formaldehyde	8.68	.298	4.65
Hexane (isomers)	3.47	.111	9000
Naphthalene	.073	.014	250
Propylene Oxide	1.61	.029	1200
Toluene	1.34	.091	3750
Xylene	1.29	.069	2175
Arsenic	.005	.029	.05
Beryllium	.00017	.000	.01
Cadmium	.016	.011	.025
Chromium	.141	.118	2.5
Cobalt	.119	.002	.5
Manganese	.124	.002	25
Mercury	.004	.000	.5
Nickel	.149	.014	5
Selenium	.0006	.011	1

None of HAPs exceed 0.5% of the PEL.

Part F

Additional Impact Analysis

All PSD permit applicants must prepare additional impacts analysis for each pollutant subject to regulation under the Act. This analysis assesses the impacts on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source. The Tenaska PSD permit application provided an additional impact analysis performed by AirPermits.com.

Economic Growth

The proposed project is expected to create approximately 35 new full-time positions. Primarily existing residents in the Pike County area will fill these positions. No appreciable increase in emissions is expected as a result of any growth, which might be associated with the proposed project.

Soils and Vegetation Analysis

A list of soil types present in the general areas was determined. Soil types include the following: Elston Sandy Loam, Ade Sandy Loam, Warsaw Sandy Loam, Rodman Gravelly Loam, Whitaker Loam, Randolph Silt Loam, Petrolia Silty Clay Loam, Armiesburg Silty Clay Loam, Genesee Fine Sandy Loam, Shoals Silt Loam, and Wakeland Silt Loam.

Vegetation in the vicinity of the proposed facility consists mainly of grasses. No sensitive aspects of the soil and vegetation in the area surrounding the facility have been identified. The secondary NAAQs, which establish the ambient concentration levels to protect soil or vegetation, will not be violated.

Federal Endangered Species Analysis

Federally endangered or threatened species are listed by the U.S. Fish and Wildlife Service; Division of Endangered Species for Indiana and includes 12 species of mussels, 4 species of birds, 2 species of bat and butterflies and 1 specie of snake. The mussels and birds listed are commonly found along major rivers and lakes while the bats are found near caves. The proposed facility is not expected to have any additional adverse effects on the habitats of the species than what has already occurred from the industrial and residential activities in the area.

Federally endangered or threatened plants as listed by the U.S. Fish and Wildlife Service, Division of Endangered Species for Indiana list two threatened and one endangered species of plants. The endangered plant is found along the sand dunes in northern Indiana while the two threatened species do not thrive in industrialized and residential areas. The proposed facility is not expected to impact the area further.

Additional Analysis Conclusions

The nearest Class I area to the electric generation facility is Mammoth Cave National Park located approximately 156 km to the south in Kentucky, well outside the 100 km Class I range. No additional analysis is required.

Finally, the results of the additional impact analysis conclude the operation of the Tenaska electric generation facility will have no significant impact on economic growth, soils, vegetation or visibility in the immediate vicinity or on any Class I area.

Part G

Summary of Air Quality Analysis

Tenaska has applied for a PSD construction permit to construct an electric generation facility near Petersburg, Pike County, Indiana. AirPermits.com of Woodinville, Washington prepared the PSD application. Pike County is designated as attainment for all criteria pollutants. PM_{10}, SO_2, NO_2, VOC, and CO emission rates associated with the proposed electric generation facility exceeded the respective significant emission rates. RPM-IV modeling results showed no significant impact to ozone formation. Modeling results taken from the latest version of the ISCST3 model showed PM_{10}, SO_2, CO and NO_2 impacts were predicted to be less than the significant impact levels. Refined modeling was not required. An air toxic analysis was preformed as a precautionary measure and no modeled concentrations were above the 0.5% of PEL. The nearest Class I area is Mammoth Cave National Park in Kentucky, approximately 156 kilometers to the south of the source. Additional impact analysis showed no significant impact on economic growth, soils, vegetation or visibility in the areas surrounding the proposed electric generation facility.

Appendix C

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Source Name:	Tenaska Indiana Partners, L.P.
Source Location:	County Road 625 East, Otwell, IN 47564
County:	Pike
Construction Permit No.:	CP-125-12760-00039
SIC Code:	4911
Permit Reviewer:	Gurinder Saini

The Office of Air Quality (OAQ) has performed the following federal BACT review for the proposed combined-cycle power plant to be owned and operated Tenaska Indiana Partners, L.P. The review was performed for the six (6) natural-gas-fired combustion turbines, six (6) duct burners, six (6) black start generators, one (1) auxiliary boiler, one (1) emergency generator, one (1) fire pump and two (2) cooling towers.

The source is to be located in Pike County, which is designated as attainment or unclassifiable for all criteria pollutants (VOC, NO_X, CO, PM_{10}, $S0_2$ and Lead). Therefore, these pollutants were reviewed pursuant to the PSD Program (326 IAC 2-2 and 40 CFR 52.21). All of the criteria pollutants, with the exception of lead, are subject to BACT review because the pollutant emissions are above PSD significant threshold levels set forth in 326 IAC 2-2. BACT is an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under 326 IAC 2-2. In accordance with the "Top-Down" analysis for Best Available Control Technology, with guidance set forth in the USEPA 1990 draft *New Source Review Workshop Manual*, the BACT analysis takes into account the energy, environment, and economic impacts on the source. These reductions may be determined through the application of available control techniques, process design, and/or operational limitations. These reductions are needed to demonstrate that the remaining emissions, after BACT implementation, will not cause or contribute to significant air pollution thereby protecting public health and the environment.

Combined-Cycle Best Available Control Technology (BACT)

(A) Six Natural-Gas-Fired Combustion Turbines and Six Natural-Gas-Fired Duct Burners

The six combustion turbines at the proposed Tenaska Indiana Generating Station combined-cycle power plant will be Mitsubishi Heavy Industry (MHI) model M501F equipped low-NOx combustion systems. The maximum heat input rating for each of the combustion turbines is 2,112 MMBtu per hour higher heating value (HHV). Auxiliary or supplemental duct firing is included as part of each combustion turbine/heat recovery steam generator system. The maximum heat input capacity for each duct burner is 550 MMBtu per hour HHV utilizing low NOx combustors. Auxiliary duct firing will be used to increase electric power production during periods of peak electrical demand. Steam injection into the turbine combustor will also be used to increase power output from each turbine. Evaporative cooling will also be used to augment power.

(1) PM / PM 10 BACT Review

There are three potential sources of filterable particulate emissions from combustion sources: mineral matter found in the fuel, solids or dust in the ambient air used for combustion and unburned carbon or soot formed by incomplete combustion of the fuel. There is no mineral matter found in the fuel (natural gas) for the proposed power generation plant. In addition, as a precautionary measure to protect the high speed rotating equipment within a combustion turbine, the inlet combustion air is filtered prior to compression and use as combustion air in the combustion turbine. Finally, the potential for soot formation in a natural-gas-fired combustion turbine with duct burners is very low because of the excess air combustion conditions under which the fuel is burned. As a result, there is no real source of filterable particulate origination from either the turbine or duct burner.

There are two sources of condensable particulate emissions from combustion sources: condensable organic matter that are the result of incomplete combustion and sulfuric acid mist which is found as sulfuric acid dihydrate. For natural-gas-fired sources such as the proposed power plant, there should be no condensible organics originating from the source because the main components of natural gas (i.e. methane and ethane) are not condensable at the temperatures found in a Method 202 ice bath. As such, any condensed organics are from the ambient air. The most likely condensable particulate matter from natural-gas-fired combustion sources is the sulfuric acid dihydrate, which results when the sulfur in the fuel and in the ambient air is combusted and cools.

Additional consideration of particulate matter generated during combustion is the use of additional NO_X and CO add-on control. When using selective catalytic reduction (SCR) to control $NO_{X,}$ PM/PM_{10} emissions increase due to the formation of ammonium nitrates and ammonium sulfates. Ammonium nitrate particles are formed when ammonia reacts with nitric acid, a derivative of NO_X emissions. Ammonium sulfate particles are formed when acid sulfate aerosols, formed during the oxidation of SO_2 emissions, react with excess ammonia. In addition the use of a catalytic oxidation system to control CO has the potential to increase PM/PM_{10}.

<u>Control Options Evaluated</u> – The following control options where evaluated in the BACT review:

Fuel Specification
Good Combustion Practice/Combustion Control
Low-Sulfur Fuel

<u>Technically Infeasible Control Options</u> – All add on control technologies (i.e. fabric filters, electrostatic precipitators, and venturi scrubbers) are technically infeasible because the only proposed fuel for this project is natural gas which has negligible amounts of ash that would contribute to the formation of PM or PM_{10}. Add-on controls have never been applied to commercial gas/oil-fired turbines.

<u>Existing BACT Emission Limitations</u> – The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database system that provides emissions limit data for industrial processes throughout the United States. The following table represents RBLC emission rates for PM/PM10 in turbine exhausts.

Company	Facility	Throughput (MMBtu/hr)	Emission Rate (lb/MMBtu)	Compliance Status
Proposed Tenaska Generating Station Energy	Turbine	2,112	0.005	Not Yet Tested (5 and 202)
	Duct Burner	550	0.0075 (CT+DB)	
PSEG Lawrenceburg IN	Turbine (7FA)	1906.4	0.0096	Good Combustion
	Duct Burner	310	0.0096 (CT + DB)	
Duke Vigo, IN	Turbine (7FA)	1984	0.011	Good Combustion
	Duct Burner	575	0.012 (CT + DB)	
Duke Kankekee, IL	Turbine (7FA)	1984	0.01	Good Combustion
	Duct Burner	575	0.015 (CT + DB)	
Selkirk Cogen., NY	Turbine (7FA)	1173	0.014	Compliant (Condensibles not tested)
	Duct Burner	206		
Whiting Clean Energy, IN	Turbine (7FA)	1735	0.0045	Not Yet Tested (5 & 202)
	Duct Burner	821	0.0045	
LSP Nelson, IL	Turbine	2166	0.0193	Not Yet Tested (5 & 201A)
	Duct Burner	350		
Gordonsville Energy, VA	Turbine (7EA)	1430	0.0035*	Compliant (Method 5)
Duke Power Lincoln, NC	Turbine (7 Frame)	1313	0.0038*	Compliant (201 or 201A)
CP&L Harstville, SC	Turbine W501	1521	0.0039*	Noncompliant (Method 5)
Hardee Station, FL	Turbine (7EA)	1268	0.0039*	Not Specified (Method 5)
CP&L Goldsboro 1, NC	Turbine (7FA)	1908	0.0047*	Not Yet Tested (201 or 201A)
CP&L Goldsboro 2, NC	Turbine (7FA)	1819	0.0049*	Not Yet Tested (201 or 201A)
Ecoelectrica L.P., PR	Turbine W501F	1900	0.005*	Not Tested (201)
SMEPA-Mosell, MS	Turbine (7EA)	1299	0.0057*	Compliant (Method 5)
Saranac Emergy, NY	Turbine (7EA)	1123	0.0062*	Compliant (Method 5)
Lakewood Cogen, NJ	Turbine (ABB GT11N)	1073	0.0023	Compliant (201A & 202)

* These limits do not include condensable PM_{10} (Method 202)

Compliance with the particulate matter limits presented in the above table is demonstrated based on measurement of either the filterable particulate fraction only or the combined filterable and condensible particulate fractions. Because the majority, if not all of the filterable particulate, is PM_{10}, and because vendor information indicates that at least half of the total particulate is condensable, the limits based solely on demonstrating compliance using only the filterable component were considered non-representative for the purpose of comparison. Therefore, these limits were eliminated from the review.

Two other facilities that have lower limits than the proposed Tenaska Generating Station are Whiting Clean Energy and Lakewood Cogeneration. The Whiting Clean Energy facility is located in a PM_{10} nonattainment area and, therefore is subject to LAER and PM_{10} emission reduction credits and has not demonstrated compliance with the lower limit. The source took a lower limit in order to avoid PM_{10} offset credits. While the Lakewood Cogeneration facility has a lower PM_{10} emission limit, the corresponding NO_X and CO emissions are higher than those for the proposed Tenaska facility. It is not expected that the proposed Tenaska facility will emit more particulate matter than these two facilities because there is no add-on control technology for combustion turbines. The top level of control for a combustion turbine is considered to be a clean burning fuel. Natural gas is the cleanest burning fuel and is, therefore, considered the best control technology.

As stated above, the combustion of natural gas generates negligible amounts of particulate matter. There is a degree of variability inherent to the test method (Method 202) used to determine compliance with the proposed particulate limits. The variability from this test result is from several factors. First, there is a large volume of exhaust gas stream compared to a small amount of particulate. For example, the concentration of particulate matter could be the same for two gas steams, however, if one of the gas streams has lower flow rate, the pound per hour emission rate would be less than a gas stream that has a higher flow rate. Second, as with any test, there is a possibility of human error, which has the potential to bias the test higher or lower than what is actually being emitted. In addition, the inlet air filters are not a hundred percent efficient in removing particulate, so any particulate that passes through the filters will also pass through the turbine and leave via the exhaust stack. The higher the background concentration of particulate matter in the ambient air the more will pass through the combustion turbine stack. Ambient air particulate concentration can vary depending on location, activity in the area, and weather conditions.

Conclusion – Based on the information presented above, the PM/PM_{10} BACT shall be the use of natural gas as the sole fuel and good combustion practice. The PM or PM10 emissions from each turbine shall not exceed 0.005 lb/MMBtu on a higher heating value basis, which is equivalent to 9.0 pounds per hour. When firing the duct burner along with the turbine, the PM or PM10 emission shall not exceed 0.0075 lb/MMBtu on a higher heating value basis, which is equivalent to 19.4 pounds per hour.

(2) NO_X BACT Review

Oxides of nitrogen (NO_X) emissions from combustion turbines consist of two types: thermal NO_X and fuel NO_X. Thermal NO_X is created by the high temperature reaction of nitrogen and oxygen in the combustion air. The amount formed is a function of the combustion chamber design and the combustion turbine operating parameters, including flame temperature, residence time, combustion pressure, and fuel/air ratios at the primary combustion zone. The rate of thermal NO_X formation is an exponential function of the flame temperature. Fuel NO_X is formed by the gas-phase oxidation of char nitrogen. Fuel NO_X formation is largely independent of combustion temperature and the nature of the organic nitrogen compound. Fuel NO_X formation is dependent on fuel nitrogen content and combustion oxygen levels. Natural gas contains a negligible amount of fuel nitrogen; therefore fuel NO_X is insignificant. As such, the only type of NO_X formation from natural gas combustion is thermal NO_X.

Control Options Evaluated – The following control options and work practice techniques were evaluated in the BACT review:

Dry Low NO_X Burners
Water/Steam Injection
$SCONO_X$ System
Selective Catalytic Reduction (SCR)
Catalytic Combustion (XONON)
Selective Non-Catalytic Reduction (SNCR)

Technically Infeasible Control Options – Three of the control options were considered to be technically infeasible: water/steam injection, and catalytic combustion (XONON), and Selective Non-Catalytic Reduction (SNCR). Water/Steam injection, which is a NO_X combustion control, is infeasible because it is less efficient than the integral Dry Low NOx combustor proposed for this project.

Catalytic Combustion (XONON)

Catalytic combustion (XONON) is a recently developed front-end technology that relies on flameless combustion of fuel to reduce NO_X emissions. The XONON system prevents the formation of thermal NO_X during combustion of the fuel by oxidizing a fuel/air mixture across small catalyst beds to burn fuel at less that the flame temperature at which thermal NO_X formation begins. The system does use a partial flame downstream to complete the combustion process, thus, producing small amounts of NO_X emissions. XONON technology replaces the traditional diffusion or lean premix combustion cans of the combustion turbine. This represents the only catalytic control that may lend itself for a reasonable retrofit to existing units. This technology has only been demonstrated and offered on small turbines (i.e. no larger than 1.5 MW). Additionally, the RBLC does not list any entries for catalytic combustion as BACT for large combustion turbines.

Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) is a technology that involves using ammonia injection, similar to SCR, but at a much higher temperature. The operating temperature window for SNCR is approximately 1600-2200 ^oF. Additionally, injecting hydrogen in with the ammonia can lower the operating temperature to 1300-2200^oF. Exhaust gas temperatures from combined-cycle facilities does not reach these high temperatures. As a result, operating at lower temperatures than the effective window of 1300-2200^oF will convert ammonia to NO_X, thereby, increasing the NO_X emissions. Furthermore, SNCR requires a longer residence time for the NO_X destruction chemical reaction to occur than what is practical in a turbine exhaust steam.

Ranking of Remaining Feasible Control Options – The following technically feasible NO_X control options were are ranked by efficiency:

Rank	Control	Facility	Control Efficiency	Emission Limit (ppm)
1	SCONOX w/Dry Low NOX Burners	Turbine	90+	2.0-4.5
		Duct Burner	90+	2.0-4.5
2	SCR w/Dry Low NO_X Burners	Turbine	80-90+	2.5-4.5
		Duct Burner	80-90+	2.5-4.5
3	Dry Low-NO_X Burners	Turbine	N/A	9-15
		Duct Burner	N/A	20-30

Discussion – Dry Low-NOx (DLN) combustion utilizes lean combustion and reduced combustor residence time as NO_X control techniques to reduce emissions from the turbine. In the past, gas turbine combustors were designed for operation with one-to-one air-to-fuel stoichiometric ratio. However, with fuel-lean combustion, the additional excess air cools the flame and reduces the rate of thermal NO_X formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors resulting in the combustion gases being at a high temperature for a shorter time, thus reducing the rate of thermal NO_X formation. The dry low-NOx burners are an integral design feature of the M501F turbines. Based on vendor specifications, the combustion turbines can achieve an emission limit of 25 ppm @ 15% oxygen.

SCONOx

The SCONOx system is a new flue gas cleanup system that uses a coated oxidation catalyst to remove both NO_X and CO and offers promise of reducing NO_X to below 3 ppmvd. The oxidation catalyst oxidizes CO to CO_2 and NO_X to NO_2. The NO_2 is then absorbed onto a potassium carbonate coated catalyst. Because the potassium carbonate coating is consumed as part of the absorption step, it must be frequently regenerated. To regenerate the potassium coating, it is contacted with a reducing gas, hydrogen, in the absence of oxygen. During regeneration, flue gas dampers are used to isolate a section of the coated catalyst from the flue gas path so the regeneration gases can be contacted with the catalyst. Once the catalyst has been isolated from the oxygen rich turbine exhaust, natural gas is used to generate hydrogen gas. An absence of oxygen is necessary to retain the reducing properties necessary for regeneration. Hydrogen reacts with potassium nitrites and nitrates during regeneration to form H_20 and N_2 that is emitted from the stack.

SCONOx catalyst is subject to the same fouling and masking degradation that is experienced by any catalyst operating in a turbine exhaust stream. Trace impurities either ingested from ambient air or internal sources accumulate on the surface of the catalyst, eventually masking active catalyst sites over time. Catalyst aging is also experienced with any catalyst operating within a turbine exhaust stream, however, due to the lack of experience and data with this system, it is difficult to confidently predict the life and cost of the catalyst. At this time, the SCONOx system has only been operated on a 34 MW facility in California and a 5 MW facility in Massachusetts, which are small industrial, cogeneration turbines. The valving system used during the regeneration step to isolate the catalyst from the exhaust gas flow requires a complete redesign before the system can be scaled up for use on units larger than that which is currently operating. There is a long-term maintenance and reliability concern related to the mechanical components on the large-scale turbine projects due to the number of parts that must operate reliably within the turbine exhaust environment.

The capital cost for SCONOx system on each CT/HRSG is based on cost quotation obtained from AAP (Ostrowski and Oegema, April, 2000). The equipment cost was obtained for a SCONOx catalyst system with at least 90 percent removal of NOx, 90 percent removal of CO and 90 percent removal of VOC emissions at base load condition. SCONOx equipment includes the catalyst module and reactor housing, regeneration gas system and catalyst removal system. The equipment cost for the M501F turbine is $15,580,700. The total cost after adding the direct and indirect costs is estimated to be $44 million. As the SCONOx system also controls CO and VOC emissions in addition to NOx, the cost effectiveness based on 90% removal of all three pollutants (NOx, CO and VOC) is $15,100 per ton of either pollutant removed. Additionally, cost effectiveness per ton of NO_X removed, is estimated to be $25,800 dollars. This cost per ton of NO_X is considered to be economically infeasible.

Compared to SCR for NOx control that can achieve a similar removal efficiency and is recognized as feasible control for combined cycle turbines, the SCONOx capital cost is approximately 10 times higher. For the proposed project for six turbines, the SCONOx system will cost $264 million, which is more than 30% of the total project capital expenditure of $600 million. Therefore, a SCONOx system is not considered BACT for this project.

Selective Catalytic Reduction

The SCR system is a post combustion control technology in which injected ammonia reacts with NO_X in the presence of a catalyst to form water and nitrogen. Technical factors related to this technology include the catalyst reactor design, optimum operating temperatures, sulfur content of the fuel, and ammonia slip. Sulfur content of the fuel can be a concern for systems that use an SCR system utilizing high sulfur fuels, however using natural gas fuel, the catalyst life can be expected to be reasonable. The SCR catalyst promotes partial oxidation of sulfur dioxide to sulfur trioxide, which combines with water to form sulfur acidic mist.

SCR, like all systems utilizing a catalyst, is subject to catalyst deactivation over time. Catalyst deactivation occurs through physical deactivation and chemical poisoning. The level of NO_X emission reduction is a function of the catalyst volume and ammonia-to-NO_X ratio. Typically SCR catalyst manufacturers will guarantee a life of three years for low emission rate, high performance catalyst systems.

A final consideration with an SCR system is ammonia slip. Manufacturers typically estimate 10-20 ppm of unreacted ammonia emissions when making NO_X control guarantees at very low emission levels, however a properly operated SCR system will typically have small amounts of ammonia slip. To achieve low NO_X limits, SCR vendors suggest a higher ammonia injection rate than what is stoichiometrically required, which results in ammonia slip. Ammonia slip can also occur when the exhaust temperature falls outside the optimum catalyst reaction, when the catalyst becomes prematurely fouled, or exceeds its life expectancy. For a given catalyst volume, higher NH_3 to NO_X ratios can be used to achieve a higher NO_X emission reduction rate.

<u>Existing BACT Emission Limitations</u> – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. In addition recent permit information has been obtained from various regulatory agencies and other sources.

The following table represents emission limitations established for similar sized combustion turbines:

Company	Facility	Throughput (MMBtu/hr)	Emission Limit ppm @ 15 O_2	Control Description	BACT or LAER
Proposed Tenaska Generating Station	M 501 F	2,112	2.5 (1-hr block)	DLN + SCR	BACT
	Duct Burner	550			BACT
Acadia Bay IN	2 X W501F	2071.4	2.5 (3-hr block)	DLN + SCR	BACT
CPV Pierce FL	GE 7FA	1918	2.5 (24-hr block)	DLN + SCR	BACT
Badger Station, WI	WM501 G	1918	2.5 (24-hr rolling)	DLN + SCR	BACT
PSEG Lawrenceburg IN	7FA Duct Burner	1906.4 310	3.0 (3-hr block)	DLN + SCR	BACT
Duke Vigo, IN	GE 7FA Duct Burner	1984 575	3.0 (3-hr block)	DLN + SCR	BACT
Whiting Clean Energy, IN	GE 7 FA	545 MW	3.0 (3-hr rolling)	DLN + SCR	LAER
Indeck – Burbonnais, LLC (Permit issued January 31, 2002	4 X Siemens 84.3 Duct Burners	1779 245	3.5 (1-hr)	DLN + SCR	BACT
Duke Kankekee, IL	GE 7FA Duct Burner	1984 575	4.5 (1-hr) 3.5 (24-hr)	DLN + SCR	BACT
Metcalf Energy Center, CA	2 X SW 501FA Duct Burner	1990 200	2.5 ppm (1-hr block)	DLN/ SCR	BACT
Sutter Power Project, CA	2 X SW 501F Duct Burner	1900 170	2.5 ppm (1-hr)	DLN/ SCR	BACT
Los Medanos, CA	2 X GE 7FA Duct Burner	1929 83	2.5 ppm (1-hr)	DLN/ SCR	LAER
La Paloma, CA	4 X ABB GT-24	1048 MW	2.5 ppm (1-hr)	DLN/ SCR or SCONOx	LAER
High Desert, CA	2 X GE 7FA or SW 501F	720 MW	2.5 ppm (1-hr)	DLN/ SCR	LAER
Delta Energy Center, CA	3 X SW 501FA	880 MW	2.5 ppm (1-hr)	DLN/ SCR	LAER
Moss Landing, CA	3 X GE 7FA	750 MW	2.5 ppm (1-hr)	DLN/ SCR or XONON	BACT
Duke Morro Bay, CA	4 X GE 7FA	1200 MW	2.5 ppm (1-hr)	DLN/ SCR	BACT
Blythe, CA	2 X SW 84.3A	520 MW	2.5 ppm (1-hr)	DLN/ SCR	LAER
Pastoria, CA	2 X GE 7FA	750 MW	2.5 ppm (1-hr)	XONON (DLN/ SCR)	LAER
Elk Hills CA	2 X GE 7FA	500 MW	2.5 ppm (2 ppm goal) (1-hr)	DLN/ SCR	LAER
Three Mountain Power CA	2 X GE 7FA	340 MW	2.5 ppm (2 ppm goal) (1-hr)	DLN/ SCR	BACT
PDC-El Paso Milford LLC CT	2 X ABB GT-24	540 MW	2.0 ppm (3-hr)	SCR	LAER
Lake Road Generating CT	2 X ABB GT-24	792 MW	2.0 ppm (3-hr)	SCR	LAER
ANP Bellingham MA	2 X ABB GT-24	580 MW	2.0 ppm (1-hr)	SCR	LAER
ANP Blackstone MA	2 X ABB GT-24	580 MW	2.0 ppm (1-hr)	SCR	LAER
Gorham Energy ME	3 X ABB GT-24	500 MW	2.0 ppm (1-hr)	DLN/ SCR	LAER
Western Midway-Sunset CA	2 X GE 7FA or SW 501F		2.0 ppm (1-hr)	DLN/ SCR	LAER
Towantic Co. CT	2 X GE 7FA		2.0 ppm (1-hr)	DLN/ SCR	LAER
Morro Bay CA	2 X GE 7FA	600 MW	2.0 ppm (1-hr)	DLN/ SCR	BACT
Otay Mesa CA	2 X GE 7FA or SW 501F or ABB GT-24	510 MW	2 ppm (1ppm goal) (3-hr) (24-hr goal)	DLN w/ SCR or SCONOx	LAER
IDC Bellingham MA	2 X GE 7FA	525 MW	1.5 ppm (1-hr)	DLN/ SCR	LAER

The above is a partial list of the recent BACT/LAER determinations for NOx emissions from the operation of “F” class turbines being permitted in the combined cycle mode.

Based on above review, most of the recent permit decisions have same NOx emission limitation at 2.5 ppm at 15% O2 or higher post SCR from the combustion turbine. This is same as the limit for the NOx emissions for the combustion turbines in the Tenaska permit.

Some sources (documented above) located in the states of Massachusetts, Connecticut and California have lower NOx emission limit of 2.0 ppm at 15% O2. This stringent limit is not applicable to the Tenaska equipment because of the following reasons:

1. The NOx BACT emission limits for two recently permitted power plants in California, the Three Mountain power LLC (TMP) and Metcalf Energy Center (MEC) are set at 2.5 ppm at 15% O2 using SCR averaged over one hour. These two permits after issuance were appealed by Citizen groups. The Environmental Appeals Board (EAB) reviewed both these permits this year. The petitioner against these permits had submitted similar arguments to the EAB with respect to lowering NOx emission limit to 2.0 ppm. The EAB in these cases upheld the permit issuer's BACT determination limits and concluded that the NOx and CO emission limits selected for the TMP[1] and MEC[2] represent BACT.

   Further, the EAB in an order denying the review of the permit for Three Mountain Power LLC stated "Petitioner's first argument in support of an emission limit of 1.3 ppm NOx measured at 15% oxygen averaged over one hour is that Massachusetts and Connecticut have made BACT determinations and issued permits requiring that large gas turbines achieve a NOx limit of 2 ppm at 15% oxygen averaged over one hour. *See* Petition for Review at 30 (citing CURE's Comments at 11-12 (Feb. 3, 2000)). However, the facilities referenced by Petitioner are located in nonattainment areas for ozone and, as such, NOx emissions from these facilities are subject to nonattainment NSR requirements...… Consequently, these facilities are required to meet the Lowest Achievable Emission Rate ("LAER") for NOx, rather than BACT; and LAER can be more

2. This limit (2.5 ppm at 15% O2) is comparable or most stringent to BACT determinations for this type of source in other states in Region 5 of EPA and other Regions (recent BACT determination for CPV Cana in State of Florida). This limit is slightly higher than the limit proposed in the California permit for similar type of Source. In a document[3] approved by California Air Resource Board (CARB), it is stated "Most BACT definitions in California are consistent with the federal LAER definition and are often referred to as 'California BACT'. One should take note not to confuse 'California BACT' with the less restrictive federal BACT. As this is a federal PSD BACT review the permit limits are less stringent than 'California BACT' but equal or more stringent than other federal BACT determinations are appropriate.

3. The OAQ, IDEM has also reviewed the CEMs and Stack test data[4] for the Los Medanos Energy Center project in Pittsburg, California. The Los Medanos project consists of GE 7 FA turbines with 2 duct burners each. The Los Medanos turbine NOx emissions are limited to 2.5 ppm at 15% O2. The duct burners have maximum heat input capacity of 83 MMBtu per hour per unit. The stack test was performed in August 2001 at full load and with duct burners in operation. The unit 1 tested at an average of 2.115 ppm @ 15% O2 and the unit 2 tested at 1.6 ppm @ 15% O2. On further scrutiny of the CEMs data it was observed that the NOx emission rate does exceed 2.0 ppm @ 15% O2 averaged over 3

[1] PSD Appeal No.01-05 before Environmental Appeals Board for Three Mountain Power LLC decided on May 30, 2001.

[2] PSD Appeal No.01-07 and 01-08 before Environmental Appeals Board for Metcalf Energy Center decided on August 10, 2001.

[3] See page 6 in "Guidance for Power Plant Siting and Best Available Control Technology", approved by Air Resource Board on July 22, 1999, issued September 1999

[4] Draft Report for Startup Emission Compliance Tests Los Medanos Energy Center, September 2001.

hours on various occasions. The emission rate consistently stays below 2.5 ppm @ 15% O2 on a 3 hour average basis. Another consideration is the size of the duct burner. Whereas Los Medanos project has 2 X 83 = 166MMBtu/hour duct burners, the Tenaska project has a 550 MMBtu/hour duct burner. The larger duct burner can increase the NOx emission rate for the Tenaska project.

4. The OAQ, IDEM has also reviewed the CEMs and Stack test data[5] for the Sutter Power Plant project in Yuba City, California. The Sutter project consists of Westinghouse 501 F turbines with 2 duct burners each. The Sutter turbine NOx emissions are limited to 2.5 ppm at 15% O2. The duct burners have maximum heat input capacity of 170 MMBtu per hour per unit. The stack test was performed in August and October 2001 at full load and part load with duct burners in operation. The unit 1 tested at an average of 2.3 ppm @ 15% O2 and the unit 2 tested at 2.19 ppm @ 15% O2. On further scrutiny of the CEMs data it was observed that the NOx emission rate does exceed 2.0 ppm @ 15% O2 averaged over 3 hours on various occasions. The emission rate consistently stays below 2.5 ppm @ 15% O2 on a 3 hour average basis. Another consideration is the size of the duct burner. Whereas Sutter project has 170 MMBtu/hour duct burners, the Tenaska project has a 550 MMBtu/hour duct burner. The larger duct burner can increase the NOx emission rate for the Tenaska project.

5. Additional matter is the question of averaging time for NOx. From the time first combined cycle turbine projects were reviewed for permit in Indiana, the OAQ, IDEM has consistently assigned an averaging period of 3 hour for NOx emissions. This was based on following:

    1. One hour averaging period is frequently used in LAER determinations especially in case of California and Massachusetts permits.

    2. The National Ambient Air Quality Standard for the NOx emissions is based on an annual average.

    3. The three hour average emission rate does protect the annual NAAQS NOx standard.

    4. In case of an excursion, it allows the source sufficient time to lower emissions to show compliance with the limit and also provides operational flexibility.

    5. The performance of these turbines at very low ambient temperature can be affected due to varying fuel requirements. Also operation at part load condition can cause occasional spike in emissions.

    6. A recent survey of regulatory agency in this regard showed that there is little consistency in this regard. The following table shows the result:

Averaging period =>	1 hour average	3 hour average	24 hour average
No. of Agencies	8	9	6

Due to above factors, the OAQ, IDEM believes that a three-hour average is sufficient to show compliance with NOx emission limit under BACT.

Therefore, the NOx emission rate at 2.0 ppm @ 15% O2 on a one-hour average is not the BACT for this source. The OAQ, IDEM has set the permit limit to 2.5 ppm @ 15% O2 at 3 operating hour block average as BACT determination.

[5] Emission Compliance Tests and RATA, revised report for 2001 for the Sutter Energy Center in Yuba City, California, January 2002.

Conclusion – Based on the information presented above, the NO_X BACT shall be the use of Dry low NO_X burners in conjunction with SCR control. The Tenaska Generating Station facility shall have an emission limit of 2.5 ppmvd @ 15% O_2 based on a 3 operating hour block average period. The emission limit is equivalent to 19.1 pounds of NO_X per hour for each combustion turbine and 24.1 pounds of NO_X per hour when its associated duct burner is in operation. Periods of power augmentation shall be limited to 1500 hours per year.

During periods of startup and shutdown (less than 50 percent load) the NO_X emissions from each turbine shall not exceed 827 pounds per event (an event is one startup and one shutdown). A start-up event for each combustion turbine shall not last longer than 4.95 hours. Also, the source will be limited to 210 events for each turbine (cold, warm or hot) per year. The total hours for start-up/shutdown events shall not exceed 650 hours per 12 consecutive month period rolled on monthly basis as determined at the end of each calendar month for each turbine. Startup is defined as the period of time from initiation of combustion firing until the unit reaches steady-state operation (i.e. loads greater than 50%). Shutdown is defined as that period of time from the initial lowering of the turbine output, with the intent to shutdown, until the time at which the combustion is completely stopped. Duct burners shall not be operated until normal operation begins.

(3) CO BACT Review

Carbon monoxide emissions from combustion turbines are a result of incomplete combustion of natural gas. Improperly tuned turbines operating at off design levels decrease combustion efficiency resulting in increased CO emissions. Control measures used to decrease the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent to newer combustor design and control systems limits the impact of fuel staging on CO emissions.

Control Options Evaluated – The following control options were evaluated in the BACT review:

Oxidation Catalyst
Good Design/Operation

Discussion – As previously stated, CO emissions are a result of incomplete combustion. CO emissions can be limited by ensuring complete and efficient combustion of the natural gas in the turbine. Complete combustion is a function of time, temperature and turbulence. Combustion control techniques are used to maximize fuel efficiency and to ensure complete combustion. Many of these controls are inherent in the design of many of the newer natural gas-fired combustion turbines and duct burners.

Oxidation Catalyst

Oxidation catalyst uses a precious metal based catalyst to promote the oxidation of CO to CO_2. The oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust. The activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include catalyst reactor design, optimum operating temperature, backpressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10}. Oxidation catalyst reactors operate in a temperature range of 700 to 900 ^{o}F. At temperatures lower than this range, CO conversion to CO_2 reduces rapidly. The catalyst is normally placed within the heat recovery steam generator (HRSG) to protect it from catalyst sintering. Cost of an oxidation catalyst can be high with the largest cost associated with the catalyst itself. Catalyst life varies, but typically a 3 to 6 year life can be expected.

The CO emissions will be limited to not-to-exceed values of 6 ppmvd @ 15% O_2 when the only the combustion turbines are operating and to 9 ppmvd @ 15% O_2 when the combustion turbines and duct burners are in operation. The total cost of a CO Oxidation Catalyst system, based on a vendor quote, will be $2.8 million with an annualized cost of $1.4 million. Therefore, the cost effectiveness for removing CO emissions using an oxidation catalyst for the Tenaska Generating Station facility is $5,700 per ton of CO removed. CO oxidation catalyst is, therefore, economically infeasible for the Tenaska Generating Station.

<u>Existing BACT Emission Limitations</u> – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. In addition recent permit information has been obtained from various regulatory agencies and other sources.

The following table represents emission limitations established for similar sized combustion turbines:

Company	Facility	Throughput (MMBtu/hr)	Emission Limit ppm @ 15 O_2	Control Description	BACT or LAER
Proposed Tenaska Generating Station	M 501 F Duct Burner	2,112 550	6.0 (24-hr block) 9.0 (24-hr block)	Good combustion or Oxidation Catalyst	BACT
Acadia Bay IN	2 X W501F	2071.4	6.0 (24-hr block)	Good combustion or Oxidation Catalyst	BACT
CPV Pierce FL	GE 7FA	1918	8.0 (24-hr block)	Good combustion	BACT
PSEG Lawrenceburg IN	7FA Duct Burner	1906.4 310	6.0 (24-hr block) 9.0 (24-hr block)	Good Combustion	BACT
Duke Vigo, IN	GE 7FA Duct Burner	1984 575	6.0 (24-hr block) 9.0 (24-hr block)	Good Combustion	BACT
Indeck – Burbonnais, LLC (Permit issued January 31, 2002	4 X Siemens 84.3 Duct Burners	1779 245	5.0 (1-hr) 7.3 (1-hr)	Good Combustion	BACT
Duke Kankekee, IL	GE 7FA Duct Burner	1984 575	4.0 (1-hr) 6.0 (1-hr)	Good Combustion	BACT
Metcalf Energy Center, CA	2 X SW 501FA Duct Burner	1990 200	6.0 (3-hr block)	Good Combustion	BACT
Sutter Power Project, CA	2 X SW 501F Duct Burner	1900 170	4.0 (24-hr bock)	Oxidation Catalyst	BACT
Los Medanos, CA	2 X GE 7FA Duct Burner	1929 83	6 (24-hr block)		BACT
High Desert, CA	2 X GE 7FA or SW 501F	720 MW	4.0 (24-hr)	Oxidation Catalyst	BACT
Duke Morro Bay, CA	4 X GE 7FA	1200 MW	4.0 (3-hr rolling) first 12 months 2.0 (3-hr rolling) after 12 months	Oxidation Catalyst	BACT
Elk Hills CA	2 X GE 7FA	500 MW	4.0 (3-hr)	Oxidation Catalyst	BACT
Three Mountain Power CA	2 X GE 7FA	340 MW	4.0 (1-hr)	Oxidation Catalyst	BACT
PDC-El Paso Milford LLC CT	2 X ABB GT-24	540 MW	2.0 (1-hr)	Oxidation Catalyst	BACT
ANP Bellingham MA	2 X ABB GT-24	580 MW	3.0 (1-hr)	Oxidation Catalyst	BACT
ANP Blackstone MA	2 X ABB GT-24	580 MW	3.0 (1-hr)	Oxidation Catalyst	BACT
IDC Bellingham MA	2 X GE 7FA	525 MW	2.0 (1-hr)	Oxidation Catalyst	LAER

The above is a partial list of the recent BACT/LAER determinations for CO emissions from the operation of “F” class turbines being permitted in the combined cycle mode.

Based on above review, most of the recent permit decisions have same CO emission limitations between 2.0 – 9.0 ppm at 15% O2 or higher post SCR from the combustion turbine. The limitations proposed by the Tenaska for the CO emissions falls in this range.

There is limited information available about the CO emissions from the gas turbines at this point in time. The permitting agencies are faced with the dilemma of considering add-on control for the CO emissions, which otherwise are below detectable level. This situation has arisen with the evolution of DLN type combustor, presently available on “F” type turbines. In an initial compliance run in Feb and May 1999 at the FPC Hines Energy Complex in Florida, the gas turbine achieved the CO emission rate of 1-3 ppm. This project used Westinghouse 501 F which used the DLN type combustor. At city of Tallahassee Purdom Station in Florida Unit 8, the emission report in September 2000 shows that CO emissions are below 1 ppm level at 100% load. Another Turbine at Tampa Electric Polk Power Station in Florida also shows CO emissions below 1 ppm for loads varying from 70% to 100%[6].

The Stack test data[7] for the Los Medanos Energy Center project in Pittsburg, California shows the CO emissions at 0.046 to 0.048 ppm at 15% O2 at full load with duct burners in operation. The permit limit for CO emissions is at 6.0 ppm @ 15% O2.

The OAQ, IDEM has also reviewed the CO CEMs and Stack test data[8] for the Sutter Power Plant project in Yuba City, California. The Sutter turbine CO emissions are limited to 4 ppm at 15% O2. The stack test shows CO emissions at 0.04 ppm at 15% O2.

The CO limits of 6 ppmvd @15% O2 while firing natural gas and without duct burner operation are low and within the range of recent BACT determinations for combustion turbines in the Country. This limit also takes into account the variation in the CO emissions due to the load change for the turbine. The decrease in the turbine load causes the CO emissions to increase. There is limited information available at this time about this variation. The recently permitted sources are being built in State of Indiana and other states. As the information about part load operation CO emissions becomes available to IDEM, OAQ, stringent limits can be set based on that for the future project. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NOX, SO2, or PM10.

For a similar source presently being permitted in another state[9], the estimated levelized costs for CO catalyst control at $2,852 to reduce emissions from the range of 8-17 ppmvd @15% O2 to a 2-4 ppm range. In view of the performance of "F" type units cited in the discussion above (Tallahassee, TECO Polk Power, Los Medanos and Sutter data) without add-on control (~ 1 ppmvd), it appears to the OAQ, IDEM that oxidation catalyst costs are substantially biased to the low side based on actual emissions.

In a letter[10], US EPA Region 2 states, "GE's data collected to date on 7FA gas turbines has demonstrated that **every unit tested has emissions of** ...**CO measured below U.S. EPA Method 10 detection levels** [emphasis in the original]. Measured data from fourteen 7FA gas turbines ...document base load CO levels averaging well below 2 ppmvd @ 15% O2 …".

The CO Oxidation Catalyst has been installed on the combined cycle combustion turbines, but the requirements to install them spring from different requirements.

In case of Duke Morro Bay Permit[11] (recent permit decision by San Luis Obispo County agency in California cited by the commentator) the district has stated as follows:

"the district has reviewed this (2 ppm) emission level and determined that the oxidation catalysts proposed for CO control and as needed to satisfy Toxic Best Available Control Technology for acrolein emissions is capable of reducing CO emissions to this level. The design of oxidation catalyst for maximum acrolein control will result in the ability to control

[6] BACT Discussion in the draft permit for CPV Cana Limited in Florida available at http://www.dep.state.fl.us/air/permitting/construction.htm website.

[7] Draft Report for Startup Emission Compliance Tests Los Medanos Energy Center, September 2001.

[8] Emission Compliance Tests and RATA, revised report for 2001 for the Sutter Energy Center in Yuba City, California, January 2002.

[9] A GE 7 FA turbine being permitted at CPV Cana Limited in Florida.

[10] Letter by Steven Riva, Chief Permitting Section at Region 2, US EPA to Robert L. Ewing, New York State Department of Environmental Conversation, for proposed Sithe Heritage Generating Station, September 27, 2000.

[11] See "Final Determination of Compliance", Duke Energy Morro Bay LLC, APCD application number 3038, issuance date August 30, 2001

CO below 2.0 ppmvd on three hour average. The district has phased in the 2.0 ppmv CO level, starting at 4.0 ppmv for the first twelve months and 2.0 ppmv thereafter…"

The other lower BACT determination is for ANP Blackstone Energy Company, Massachusetts, which has CO emission limit of 3.0 ppm @15% O2. This project consists of ABB GT-24 turbines. These turbines are not equipped with the DLN type combustor for controlling CO emissions. Therefore inlet CO concentration for the Oxidation Catalyst is much higher than the GE 7 FA type turbine. The town of Blackstone, Massachusetts is located in non-attainment area for Ozone. The project VOC emissions after control (using oxidation catalyst to control VOC emissions) are at 49 tons per year just below 51 tons per year the threshold for non-attainment review. The project proponent installed the catalyst to avoid LAER applicability.[12]

As explained in detail earlier, extremely low CO emissions have been observed from different "F" class turbines. The lower BACT determinations listed in the table above are located in California, Massachusetts and Connecticut. In a document[13], CARB has stated on page 6 "Most BACT definitions in California are consistent with the federal LAER definition and are often referred to as 'California BACT'. One should take note not to confuse 'California BACT' with the less restrictive federal BACT. As this is a federal PSD BACT review the permit limits are less stringent than 'California BACT' but equal or more stringent than other federal BACT determinations are appropriate.

The Massachusetts and Connecticut sources are located in non-attainment area and are subject to LAER determinations.

In the matter of denial of permit review in case of Metcalf Energy Center[14] (which has a CO emission limit of 6.0 ppm @15% O2 and was issued after the Three Mountain Permit) the EAB stated as follows:

> "With respect to the difference between TMP's permitted CO BACT limit (4 ppm) and Metcalf's (6 ppm), it is important to understand that our decision in *TMP* made no judgment as to whether 6 ppm could constitute BACT for CO emissions. The only CO-related issue before us in that case was whether a limit *lower than* 4 ppm should have been selected as CO BACT. We answered that question in the negative. *See TM*P, slip op. at 19, 10 E.A.D. ___ (finding that 4.0 ppm CO limit is "consistent with the CO limit for other sources in Region IX, which has been determined on a case-by-case basis to be in the range of 4.0 to 6.0 ppm with three hours being the most common averaging time"); *i*d. at 19-22, 10 E.A.D. ___ (analyzing petitioner's arguments and finding no showing of clear error or other grounds for review of permit condition).".

This limit (6.0 ppm at 15% O2 without duct firing and 9 ppm @ 15% O2 with duct firing) is comparable to BACT determinations for this type of source in other states in Region 5 of EPA and other Regions. This limit is slightly higher than the limit proposed in the California permit for similar type of Source.

As recent as August 2001, the EAB agreed with Bay Area Air Quality district's BACT determination for CO emissions limit of 6.0 ppm @ 15% O2 with an averaging period of 3 hour. The OAQ, IDEM concurs that it has allowed a longer averaging period (24-hour) for the CO emissions. It believes that performance characteristic and CO emissions at low

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[12] ANP Blackstone Energy Company approval issued April 16, 1999.

[13] See "Guidance for Power Plant Siting and Best Available Control Technology", approved by Air Resource Board on July 22, 1999, issued September 1999

[14] This orders has been referenced previously.

ambient temperature is unknown for the turbines. Therefore, it feels 24 operating hour average allows the Source adequate cushion to comply with the BACT limit.

The OAQ, IDEM has decided to set CO limits reflecting the "new and clean test" guarantees rather than actual performance because turbine manufacturer will not (yet) guarantee the lower values. The OAQ, IDEM will gather more information and may substantially reduce CO limits in future projects if such performance is maintained at the new installations throughout the state.

There is no benefit in making the applicant comply with a lower limit at this time just because the performance at another site was far better than guaranteed or expected. There also appears to be no environmental benefit in installing a catalytic oxidation system. Rather there are energy and environmental implications in terms of increased pressure drop causing loss of electricity generation and disposal of used catalyst respectively. The applicant will install a continuous CO monitor. It is expected that data from continuous measurement will show on a continuous basis, that oxidation catalyst is not needed and is not cost effective for this project.

Further, there is a large variation in CO emissions due to variations in the ambient temperature. For the lean premix type of combustors that have tested at CO levels less than 0.6 ppm without using CO oxidation catalyst, this performance may be achievable in the moderate temperature in Florida and California. This level of performance may be achievable under conditions when ambient temperature is pretty high. As the ambient temperature falls, the CO emissions from the turbine increase. Further the NOx and CO emissions have an inverse relationship. The NOx limit on this turbine is most stringent as shown above. Also, the turbine in Indiana will be subject to much lower temperature conditions than the turbine projects in California and Florida. Therefore, there is little information available to support long term performance at low levels of CO. Further the air quality modeling performed for this source at 6 ppm CO emissions at 15% O2 do not cause any significant impacts on the environment.

A cost analysis for the proposed Tenaska Generating Station Source shows a cost of 5,700 dollars per ton of CO removed per turbine and duct burner. The high cost is a result of low inlet CO emissions and limit on hours under power augmentation when the CO emissions are high. With a lower inlet emission, the cost per ton of CO removed increases, making add-on CO controls economically infeasible. Other facilities have been required to use an oxidation catalyst because they were subject to LAER, which does not take into account economics when determining emission control.

Conclusion – Based on the information presented above, the CO BACT shall be good design/operation and natural gas as the only fuel. The CO emission from each combustion turbine shall not exceed 6 ppmvd at 15% O_2 based on 24 operating hour block average period, which is equivalent to 27.8 pounds per hour. The CO emissions from each combustion turbine when its associated duct burner is fired shall not exceed 9 ppmvd at 15% O_2 based on a 24 hour operating block average period, which is equivalent to 52.8 pounds per hour. During the power augmentation mode, the CO emissions from the gas turbine and duct burner combined shall not exceed 53.0 ppm at 15% O2. This is equivalent to 290.6 pounds per hour. Periods of power augmentation shall be limited to 1500 hours per year.

During periods of startup and shutdown (less than 50 percent load) the CO emissions from each turbine shall not exceed 13558 pounds per event (an event is one startup and one shutdown).

(4) SO_2 and H_2SO_4 Mist BACT Review

Sulfur dioxide (SO_2) emissions are emitted from combustion turbines as a result of the oxidation of the sulfur in the fuel. SO_2 emissions are directly proportional to the sulfur content of the fuel. The SO_2 emissions from natural-gas-fired turbines are low because natural gas has a low sulfur content (typically less than 2 grains of sulfur per standard cubic foot of gas). A properly designed and operated turbine utilizing low sulfur natural gas will have low SO_2 emissions.

Sulfuric acid mist emissions are included in this BACT analysis since these emissions are above the PSD significant threshold of 7 tons per year.

Control Options Evaluated – the following control options were evaluated in the BACT review:

Flue Gas Desulfurization System (Wet or Dry Scrubber)
Use of Low Sulfur Fuel

Discussion – A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. FGD is an established technology principally on coal fired and high sulfur oil fired steam electric generating stations. FGD systems have not been installed on combustion turbines because of technical and cost factors associated with treating large volumes of high temperature gas containing low SO_2 and H_2SO_4 concentration in the exhaust gases. FGD typically operate at an inlet temperature of approximately 400 to 500 ^oF. The concentration of SO_2 in the exhaust gas is the driving force for the reaction between SO_2 and the reagent. Therefore, removal efficiencies are significantly reduced with lower inlet concentrations of SO_2. FGD systems are listed in the RBLC as BACT for sources high in SO_2 emissions. Even though the SO_2 and H_2SO_4 concentrations in the exhaust gases are very low, and the airflow volume is large, the scrubbing systems are technically feasible. Wet scrubbing FGD system is considerably cheaper than dry scrubbing. Therefore wet scrubbing is analyzed further in this analysis.

The basic equipment cost for installation of a wet scrubber are an average of $5 per cubic feet per minute of flow rate. The cost estimate is based on a vendor information from 1994 obtained by the applicant. The cost has been scaled up to account for inflation. The total capital cost of a wet scrubber on one combustion turbine system is estimated at $14 million. The annualized cost for the wet scrubbing operation is $ 5.34 million per year. Assuming a control efficiency of 99% (which is unlikely for the dilute airflow from the gas turbine exhaust), the cost effectiveness of this control option will be $57,700 per ton of total SO_2 and H_2SO_4 removed.

The wet scrubber FGD systems also have energy and environmental impacts associated with their operation. A significant amount of energy is required to operate a FGD system due to the pressure drop over the scrubbers. There are also environmental impacts due to the disposal of the spent reagent and the high water use required for a wet scrubbing system.

For the economic, energy, and environmental reasons presented above, FGD was excluded from further consideration in the BACT analysis.

The use of low sulfur fuels was the next level of control that was evaluated for the proposed facility. Natural gas has the lowest sulfur content of all the fossil fuels. The NSPS established a maximum allowable SO_2 emission associated with combustion turbines and requires either an SO_2 emission limitation of 150 ppmvd at 15 percent oxygen or a maximum fuel content of 0.8 percent by weight (40 CF 60 Subpart GG).

Natural gas combustion results in SO_2 emissions at approximately 1 ppmvd. Therefore, the very low SO_2 and H_2SO_4 emission rate that results from the use of natural gas as the sole fuel represents BACT for control of SO_2 emissions from the combustion turbine.

Conclusion – Based on the information presented above, the SO_2 and H_2SO_4 BACT shall be the use of low sulfur natural gas (less than 0.8 percent sulfur by weight) and good combustion practices. The SO_2 and H_2SO_4 emissions from each turbine with duct burners firing shall not exceed 0.0055 lb/MMBtu and 0.0034 lb/MMBtu respectively. This is equivalent to 14.7 pounds of SO_2 per hour and 8.1 pounds of H_2SO_4 per hour.

(5) VOC BACT Review

The VOC emissions from natural-gas-fired sources are the result of two possible formation pathways; incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three variables; time, temperature and turbulence. Once the combustion process begins, there must be enough residence time at the required combustion temperature to complete the process, and during combustion there must be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air. Combustion systems with poor control of the fuel to air ratio, poor mixing, and insufficient residence time at combustion temperature have higher VOC emissions than do those with good controls.

Control Options Evaluated – The following control options and work practice were evaluated in the BACT review:

Catalytic Oxidation
Good Design/Operation

Discussion – An oxidation catalyst designed to control CO would also provide control for VOC emissions. The level of control is dependent on the content of the natural gas. The same technical factors that apply to the use of an oxidation catalyst technology for control of CO emissions (narrow operating temperature range, loss of catalyst activity over time, and system pressure losses) apply to the use of this technology for collateral control of VOC emissions.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents similar operations that have been recently permitted.

Company	Facility	Throughput (MMBtu/hr)	Emission Limit lb/MMBtu	Control Description	BACT or LAER
Proposed Tenaska Generating Station	M 501 F	2,112	0.0015	Good combustion or Oxidation Catalyst	BACT
	Duct Burner	550	0.0051		
Acadia Bay IN	2 X W501F	2071.4	0.0034	Good combustion or Oxidation Catalyst	BACT
PSEG Lawrenceburg IN	7FA Duct Burner	1906.4 310	3 lb/hour 7 lb/hour	Good Combustion	BACT
Duke Vigo, IN	GE 7FA Duct Burner	1984 575	0.0016 0.008	Good Combustion	BACT
Metcalf Energy Center, CA	2 X SW 501FA Duct Burner	1990 200	0.00126	Good Combustion	California BACT Federal LAER
Sutter Power Project, CA	2 X SW 501F Duct Burner	1900 170	1 ppm	Oxidation Catalyst	California BACT Federal LAER

The RBLC does not list any entries that require an oxidation catalyst for a combined-cycle operation reviewed under PSD BACT. Also an oxidation catalyst would not be economically feasible because of the lower inlet VOC emissions associated with new combustion technology. The Metcalf Energy Center and Sutter power plants have VOC emission rates lower than the proposed facility. The difference in VOC emissions is due to different turbine models and site-specific conditions. Although the VOC emission rate at Metcalf Energy Center is lower than the proposed Tenaska permit, the Metcalf Energy Center has not yet shown compliance with this limit and therefore is not demonstrated as such.

Conclusion – Based on the information presented above, the VOC BACT shall be the use of natural gas and good combustion practices. The VOC emissions from each turbine shall not exceed 0.0015 lb/MMBtu, which is equivalent to 1.6 pounds VOC per hour. Each combustion turbine when its associated duct burner is firing shall not exceed 0.0051 lb/MMBtu, which is equivalent to 12.1 pounds VOC per hour. During the power augmentation mode, the VOC emissions shall not exceed 0.01 lb/MMBtu which is equivalent to 25.5 pounds VOC per hour.

(B) Cooling Tower

Evaporative cooling towers are designed to cool process cooling water by contacting the water with air, and evaporating some of the water. Thus, these units use the latent heat of water vaporization to exchange heat between the process air and the air passing through the tower. This type of cooling tower typically contains a wetted medium to promote evaporation, by providing a large surface area and/or by creating many water drops with a large cumulative surface area. Some of the liquid water may be entrained in the air stream and be carried out of the tower.

(1) PM_{10} BACT Review

Emissions of particulate matter from cooling towers are created when water droplets escaping the tower, evaporate, and the dissolved and suspended solids within these droplets become airborne. Particulate emissions from cooling towers are controlled by installing drift eliminators, devices that are designed to minimize total liquid drift (dissolved solids on water droplets from evaporative cooling towers).

Control Options Evaluated

Drift Eliminators

Discussion – The technologies available to control PM_{10} emissions from evaporative cooling towers are limited to devices that minimize drift. Drift eliminators represent the top level of PM control technology for cooling towers. Drift eliminators consist of several layers of plastic chevrons located within the cooling tower to knock out and coalesce fine water droplets before they can be emitted to the atmosphere.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents the more stringent BACT emission limitations for cooling towers:

Company	Facility	Control	Total Liquid Drift (% flow)	PM/PM_{10} BACT Limitations (lb/hr)	Compliance Status
Proposed Tenaska Facility	Cooling Tower (14 cell)	Drift Eliminator	0.0005	1.09	N/A
Duke Vigo Facility	Cooling Tower (12 cell)	Drift Eliminator	0.0006	1.05	N/A
Crown/Vista Energy, NJ	Cooling Tower	Drift Eliminator	0.1	5.9	None Required
Texaco Bakersfield	Cooling Tower	Cellular Type Drift Eliminator	---	1.26	None Required
Ecoelectrica LP, PR	Cooling Tower	2-Stage Drift Eliminator	0.0015	60	None Required
Lakewood Cogen, NJ	Cooling Tower	Drift Eliminator	0.002	0.874	None Required
Crystal River, Units 1,2,3, FL	Cooling Tower	High Eff. Drift Eliminator	0.004	428	None Required
Crystal River, Units 4,5, FL	Cooling Tower	High Eff. Drift Eliminator	---	175	None Required

Emissions of particulate matter from cooling towers are created when water droplets escaping the tower evaporate and the dissolved and suspended solids within these droplets become airborne. For a given solids concentration (defined by the cooling water source, tower design and operating specifications), particulate matter emissions from cooling towers depends on the amount of water that drifts from the tower. The amount of drift from evaporative cooling towers, usually expressed as a percent of circulating water flow, is called liquid drift. Total liquid drift is controlled by drift eliminators, which are installed in the tower cells. The proposed Tenaska cooling towers has one of the lowest drift percentage in the above list.

Conclusion – Based on the information presented, the PM BACT shall be to use high efficiency drift eliminators on each cooling tower cell. The total liquid drift rate shall not exceed 0.0005 percent. The total particulate emissions from the cooling towers shall not exceed 1.09 pounds per hour.

(C) Auxiliary Boiler

The auxiliary boiler has a maximum heat input capacity of 40 MMBtu per hour, and will exclusively use natural gas as fuel. The auxiliary boiler will be limited to 1,000 operating hours per year. The purpose of the auxiliary boiler is to provide heat to the heat recovery steam generator (HRSG) steam drums during shutdown periods to prevent lengthy cold startups thus reducing the increased emissions associated with startup conditions. The auxiliary boiler will also be used to provide steam for sparging the condensed water used in the HRSG to remove dissolved air and supplying sealing steam to the steam turbines when they are shut down to reduce corrosion and maintain the vacuum on the condensate tank. All of these operations will occur when the HRSGs are shut down.

(1) PM BACT Review

There are three potential sources of filterable emissions from combustion processes: mineral matter found in the fuel, solids or dust in the ambient air used for combustion, and unburned carbon formed by incomplete combustion of the fuel. Due to the fact that natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate mater from natural gas combustion has both filterable and condensable fractions. The particulate matter generated from natural gas combustion is usually larger molecular weight hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

There are two sources of condensable particulate emissions from combustion processes: condensable organic matter that are the result of incomplete combustion and sulfuric acid mist which is found as sulfuric acid dihydrate. For natural gas-fired sources such as the auxiliary boilers, there should be no condensable organic matter originating from the source because the main components of natural gas (i.e. methane and ethane) are not condensable at the temperatures found in Method 202 ice bath. As such, any condensed organics are from the ambient air. The most likely condensable particulate matter from natural gas combustion sources is the sulfuric acid dihydrate, which results when the sulfur in the fuel and the ambient air is combusted and then cools.

Control Options Evaluated – The following control options were evaluated in the BACT review:

Fabric Filter (Baghouse)
Electrostatic Precipitator (ESP)
Wet Scrubber

Technically Infeasible Control Options – All control options are basically technically infeasible because the sole fuel for the proposed auxiliary boilers is natural gas, which has little to no ash that would contribute to the formation of PM or PM_{10}. Add-on controls have never been applied to commercial natural gas fired boilers, therefore, add on particulate matter control equipment will not be considered in this BACT review.

Existing BACT Emission Limitations – The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database that provides emission limit data for industrial processes throughout the United States. The database for boilers contains many entries, below are some of the entries of the more stringent limitations.

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed Tenaska Facility	Boiler	40	0.0075	lb/MMBtu	Good Design and Operation
Air Liquide America Corp, LA	Boiler	95	0.01	lb/MMBtu	Good Design and operation, use natural gas as fuel
Darling International, CA	Boiler	31.2	0.0137	lb/MMBtu	No control
Kamine/Besicorp Corning L.P., NY	Auxiliary Boiler	33.5	0.0051	lb/MMBtu	Combustion control
Kamine/Besicorp Syracuse L.P., NY	Utility Boiler	33	0.01	lb/MMBtu	Fuel specification
Mid-Georgia Cogeneration	Boiler	60	0.005	lb/MMBtu	Complete Combustion
O.H. Kruse Grain and Milling, CA	Backup Boiler	10	0.012	lb/MMBtu	No Control
Solvay Soda Ash Joint Venture Trona Mine/Soda Ash, WY	Boiler	100	5	lb/MMBtu	Minimal Particulate Emissions and Low Emitting Fuel

The BACT for PM/PM_{10} listed in the RBLC for natural-gas-fired boilers is combustion control. All of the above listed entries utilize a fuel specification of natural gas or good design and operation (i.e. good combustion). As stated above, PM/PM_{10} emissions from natural-gas-fired sources are low, making add on PM/PM_{10} control both economically and technically infeasible. The boiler at the proposed Tenaska plant is limited on hours of operation. The other sources with lower emission limits are not limited and therefore not considered further in this discussion.

<u>Conclusion</u> – Based on the information presented above, the PM/PM_{10} BACT for the auxiliary boiler is good combustion practice, the use of natural gas as its only fuel, and limited to 1000 hours of operation per year. The PM/PM_{10} emissions from the 40 MMBtu/hr auxiliary boiler at the proposed Tenaska Facility, shall not exceed 0.0075 lb/MMBtu, which is equivalent to 0.3 pounds per hour.

(2) NO_X BACT Review

Nitrogen oxide formation during combustion consists of three types, thermal NO_X, prompt NO_X, and fuel NO_X. The principal mechanism of NO_X formation in natural gas combustion is thermal NO_X. The thermal NO_X mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air. Most NO_X formed through the thermal NO_X is affected by three factors: oxygen concentration, peak temperature, and time of exposure at peak temperature. As these factors increase, NO_X emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural-gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g. combustion air temperature, volumetric heat release rate, load, and excess oxygen level). The second mechanism of NO_X formation, prompt NO_X, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X, reactions occur within the flame and are usually negligible when compared to the amount on NO_X formed through the thermal NO_X mechanism. The final mechanism of NO_X formation, fuel NO_X, stems from the evolution and reaction of fuel-bonded nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NO_X formation through the fuel NO_X mechanism is insignificant.

Control Options Evaluated – The following control options were evaluated in the BACT review:

Flue Gas Recirculation (FGR)
Low NOx Burners

Discussion – Flue Gas Recirculation (FGR) incorporates the recirculation of a portion of the flue gas back to the primary combustion zone as a replacement for the combustion air. The recirculated combustion products provide inert gases that lower the adiabatic flame temperature and the overall oxygen concentration in the combustion zone. As a result, FGR controls NO_X emissions by reducing the generation of thermal NO_X.

Low NOx burners are a specially designed set of burners that employ two-staged combustion within the burner. Primary combustion typically occurs at a lower temperature under oxygen deficient conditions and secondary combustion is completed with excess air.

Existing BACT Emission Limitations – The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database system that provides emission limit data for industrial processes throughout the United States. The database for boilers is large, containing over 200 entries. The following table represents more stringent emission limitations for similar boilers:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed Tenaska Facility	Boiler	40	0.049	lb/MMBtu	Good Design and Operation
Air Liquide America Corp, LA	Boiler	95	0.05	lb/MMBtu	Good Design and operation, use natural gas as fuel
Darling International, CA	Boiler	31.2	0.036	lb/MMBtu	Low NO_X Burner w/FGR
Huls America, AL	Boiler	38.9	0.075	lb/MMBtu	Low NO_X Burners
I/N Kote, IN	Boiler	70.8	0.05	lb/MMBtu	Fuel Spec. and FGR
Kamine/Besicorp Corning, NY	Boilers	33.5	0.32	lb/MMBtu	Low NO_X Burners
Kamine/Beiscorp, NY	Boilers	33	0.035	lb/MMBtu	FGR
Mid-Georgia Cogen., GA	Boiler	60	0.1	lb/MMBtu	Low NO_X Burner w/FGR
O.H. Kruse Grain and Milling, CA	Boiler	10	0.106	lb/MMBtu	No Control
Sunland Refinery, CA	Boiler	12.6	0.36	lb/MMBtu	Fuel Spec. and Low NO_X Burners
Toyota Motor Corp, IN	Boiler	58	0.1	lb/MMBtu	Low NO_X Burner

Entries from the RBLC indicate that BACT for boilers utilizing natural gas is Low NOx burners. Some sources have used FGR coupled with Low NOx burners for NO_X emission control. The proposed Tenaska Facility will have a fuel usage limitation, equivalent to 1,000 hours of operation per year. Because of this limitation, FGR would be economically infeasible, therefore, BACT will be the use of Low NOx burners.

Conclusion – Based on the information presented above, the NO_X BACT shall be the use of Low NO_X burner design in conjunction with a fuel specification of natural gas only, and a fuel usage limitation, equivalent to 1,000 hours of operation per year. The auxiliary boiler shall not exceed 0.049 lb/MMBtu, which is equivalent to 1.9 pounds per hour.

(3) SO_2 BACT Review

Sulfur dioxide emissions from natural-gas-fired combustion sources are low because natural gas has a low sulfur content. A properly designed and operated boiler utilizing low sulfur natural gas will insure minimal SO_2 emissions.

Control Options Evaluated – the following control options were evaluated in the BACT review:

Flue Gas Desulfurization System
Use of Low Sulfur Fuel

Discussion – A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. Lime is injected by a spray dryer into the flue gas in the form of fine droplets under well-controlled conditions such that the droplets will absorb SO_2 from the flue gas and then become dry particulate due to evaporation of water. A particulate control device then captures the dry particulate. The captured particles are removed from the system and disposed.

This control option will generate dry solid waste consisting mainly of lime and $CaSO_4$. This waste must be disposed of in a solid waste landfill giving this option additional environmental concerns. Removal efficiencies decrease as the amount of sulfur contained in the fuel decreases. Also natural gas contains very little sulfur, thus making any FGD economically infeasible. Based on additional environmental concerns with the FGD solid waste, low sulfur removal efficiencies, and cost to control, FGD is eliminated from this BACT analysis.

The use of low sulfur fuels was the next level of control that was evaluated for the proposed facility. Natural gas has the lowest sulfur content of all the fossil fuels. The NSPS established a maximum allowable SO_2 emission associated with combustion turbines and requires either an SO_2 emission limitation of 150 ppmvd at 15 percent oxygen or a maximum fuel content of 0.8 percent by weight (40 CF 60 Subpart GG). Therefore, the very low SO_2 emission rate that results from the use of natural gas as the sole fuel represents BACT for control of SO_2 emissions from the auxiliary boiler.

Conclusion – Based on the information presented above, the SO_2 BACT shall be the use of low sulfur natural gas (less than 0.8 percent sulfur by weight), good combustion practices, and a fuel usage limitation, equivalent to 1,000 hours of operation per year. The SO_X emission limit from the boiler shall not exceed 0.0006 lb/MMBtu, which is equivalent to 0.1 pounds of SO_2 per hour.

(4) CO BACT Review

Carbon monoxide emissions from boilers are a result of incomplete combustion of natural gas. Improperly tuned boilers operating at off design levels decrease combustion efficiency resulting in increased CO emissions. Control measures taken to decrease the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent to newer combustor design and control systems limits the impact of fuel staging on CO emissions.

Control Options Evaluated – The following control options were evaluated in this BACT review:

Good Combustion Control

Discussion – Good combustion practice is considered BACT for CO control on natural-gas-fired boilers. Burner manufactures control CO emissions by maintaining various operational combustion parameters. Fuel conditions, draft and changes in air can be adjusted to insure good combustion.

Existing BACT Emission Limitations – The EPA RBLC provides emission limit data for industrial processes throughout the United States. The following table represents the more stringent BACT emission limitations established for boilers:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed Tenaska Facility	Boiler	40	3.2	Lb/hr	Good Design and Operation
Air Liquide America Corp, LA	Boiler	95	3.7	Lb/hr	Good Design and operation
Mid-Georgia Cogen., GA	Boiler	60	3	Lb/hr	Complete Combustion
Archer Daniels Midland Co., IL	Boiler	350	14	Lb/hr	Good Combustion practices
Darling International, CA	Boiler	31.2	2.8	Lb/hr	Good Combustion
Indelk Energy, MI	Boiler	99	14.85	Lb/hr	Combustion Control
Kamine/Besicorp, NY	Boiler	33	1.26	Lb/hr	No controls
Lakewood Cogen., NJ	Boiler	131	5.5	Lb/hr	Boiler Design
Champion International, AL	Boiler	5.8	0.522	Lb/hr	Good Combustion Practice
Stafford Railsteel Corp., AR	Boiler	46.5	0.7	Lb/hr	Fuel Spec.
Quincy Soybean Co., AR	Boiler	68	10.6	Lb/hr	Good Combustion Practices

All of the entries listed in the above table list good combustion practice and good design/operation as CO BACT. As stated above CO emissions are a result of incomplete combustion of natural gas. The boiler at the proposed Tenaska plant is limited on hours of operation. The other sources with lower emission limits are not limited and therefore not considered further in this discussion.

Conclusion – Based on the information presented above, the CO BACT shall be the use good combustion practice and a fuel usage limitation, equivalent to 1,000 hours of operation per year. CO emissions from the auxiliary boiler shall not exceed 0.0824 lb/MMBtu, which is equivalent to 3.2 pounds of CO per hour.

(5) VOC BACT Review

The VOC emissions from natural gas-fired sources are the result of two possible formation pathways: incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three variables; time, temperature and turbulence. Once the combustion process begins, there must be enough residence time at the required combustion temperature to complete the process, and during combustion there must be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air. Combustion systems with poor control of the fuel to air ratio, poor mixing, and insufficient residence time at combustion temperature have higher VOC emissions than do those with good controls.

Control Options Evaluated – The following control options and work practice were evaluated in the BACT review:

Thermal Oxidation
Catalytic Oxidation
Good Design/Operation

Discussion – Thermal oxidation is a proven technology to control VOC emissions, however, it is rarely used on natural-gas-fired sources. Because of the low VOC concentration generated from the use of natural gas and good combustion practice, the thermal oxidation technology is ineffective. In addition, the thermal oxidation technology requires additional combustion of natural gas, which in turn would generate more emissions.

Oxidation catalyst technology uses precious metal-based catalysts to promote the oxidation of CO and unburned hydrocarbons to CO_2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature. The optimal operating temperature range for VOC conversion ranges from 650 to 1000^{o}F. In addition the use of an oxidation catalyst would require additional combustion of natural gas, which increases NO_X and CO emissions.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents the more stringent BACT emission limitations for boilers:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed Tenaska Facility	Boiler	40	0.2	lb/hr	Good Design and Operation
Mid-Georgian Cogen., GA	Boiler	60	0.3	lb/hr	Complete Combustion
Stafford Railsteel Corp., AR	Boiler	46.5	0.8	tpy	Fuel Spec. Natural Gas
Waupaca Foundry, IN	Boiler	93.9	0.55	lb/hr	Good Combustion Practice
Weyerhaeuser Co., MS	Boiler	400	0.52	lb/hr	Efficient Operation
Willamette Industries, LA	Boiler	335	1.0	lb/hr	Design and Operation
Kamine/Besicorp, NY	Boiler	2.5	0.01	lb/hr	No controls
Transamerica Refining Corp., LA	Boiler	1.2	0.01	lb/hr	Good Combustion Practices

The majority of the entries in the RBLC list good combustion, fuel specification, and good design and operation as BACT for VOC emission control. For boilers with similar heat input capacities as the proposed, a VOC emission limit of 0.2 lb/hr is one of the lowest emission rates. The other boilers with lower emission rate are very small and therefore are not considered further in this BACT.

Conclusion – Based on the information presented above, the VOC BACT for the auxiliary boiler at the Proposed Tenaska Facility shall be good design and operation, and a fuel usage limitation equivalent to 1,000 hours per year. The boiler shall not exceed 0.0054 lb/MMBtu, which is equivalent to 0.2 pounds of VOC per hour.

(D) Black Start Generators, Emergency Generator and Fire Water Pump

The source consists of following auxiliary equipment:

(a) Six (6) black-start diesel generators, each with a maximum rated capacity of 19.1 MMBtu/hr HHV, utilizing low sulfur diesel fuel.

(b) One (1) diesel fire pump, with a maximum rated capacity of 0.95 MMBtu/hr HHV utilizing low sulfur diesel fuel.

(c) One (1) emergency diesel generator, with a maximum rated capacity of 10.1 MMBtu/hr HHV utilizing low sulfur diesel fuel.

This equipment is not to be used for the production of electricity for the sale and generally used in case of emergency. The BACT is as follows:

1. The total fuel input for each black start generator shall not exceed 94,733 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

2. The total fuel input for the fire pump shall not exceed 6,504 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

3. The total fuel input for the emergency generator shall not exceed 23,683 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

4. The sulfur content of the diesel fuel used by the emergency generator shall not exceed 0.05 percent by weight.

5. Perform good combustion practice.